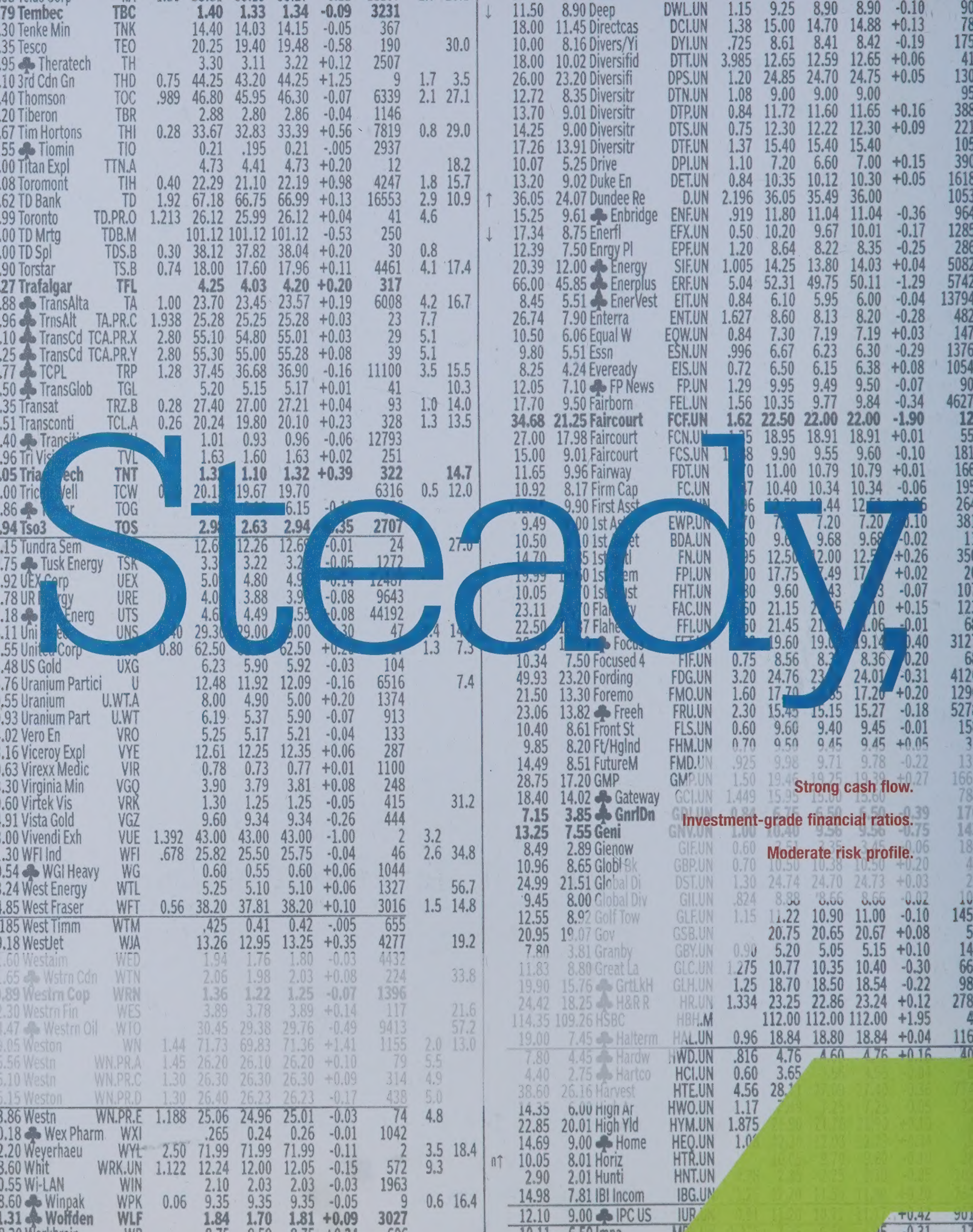
TransAlta

2006 ANNUAL REPORT

Ready,

Strong business model. Diversified generating assets. Technical and commercial expertise. Environmental leadership. Financial discipline.



Steady,

Strong cash flow.

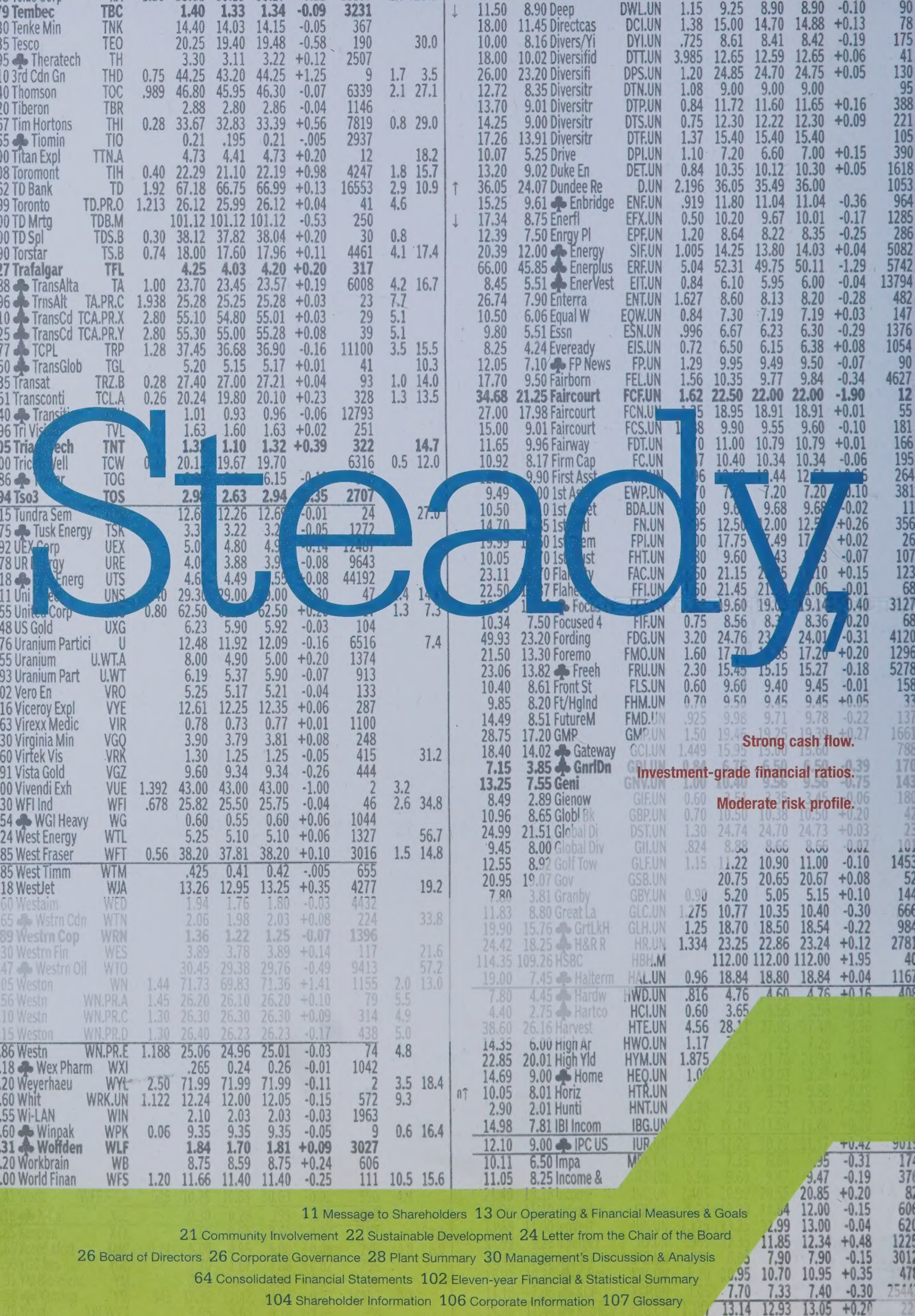
Investment-grade financial ratios.

Moderate risk profile.

Balanced, disciplined, sustainable growth in the markets we know.

Grow!

Pull tab to learn more.



Steady,

Strong cash flow.

Investment-grade financial ratios.

Moderate risk profile.

Wholesale power generator

48,213

gigawatt hours produced in 2006

TransAlta is ready for growth.

Over the next five years, we plan to grow cash flow and earnings through disciplined management of our existing business and by increasing our installed megawatts. Our goal is to grow our installed capacity by an average of five per cent per year.

The 252 MW Campeche power plant in Mexico is fully contracted until 2028.

We will invest in projects that:

- Build on our market knowledge, technical expertise and commercial strengths.
- Focus on regions where we operate, technologies we know and fuels we currently use.
- Support a 10 per cent total shareholder return and a 10 per cent return on capital employed over the long term.

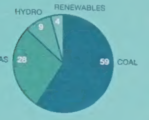
We will build on our strengths:

The 75 MW McBride Lake wind farm in southern Alberta is a joint venture between TransAlta and ENMAX Corporation.

We approach growth in a disciplined manner – spending dollars shrewdly and responsibly.

Capacity by Fuel Type

(%)
(includes plants in development)



GENERATION FACILITIES	CAPACITY OWNED
Coal-fired plants	4,887 MW
Coal-fired plant (IN DEVELOPMENT)	278 MW
Hydro plants	807 MW
Gas-fired plants	2,464 MW
Wind-powered plants	152 MW
Wind-powered plant (IN DEVELOPMENT)	76 MW
Geothermal plants	163 MW
Corporate offices	
Energy Marketing offices	

For a more detailed breakdown of our assets, please turn to page 28.

We have a strong portfolio of generating assets in markets primed for growth.

In each of our markets, we are well positioned for growth. Alberta is experiencing strong economic growth driven by the global demand for hydrocarbons. Australia is benefiting from the surge in demand for resources that our customers produce. In Eastern Canada, Mexico and the Western United States, we're responding to our customers' growth and requests for cleaner energy alternatives. We have excellent relationships with our customers and we are known for safe and reliable operations.

operational excellence,

Reliability: Unplanned Outages & Derates

(%)

Preventative maintenance and repairs during unplanned outages and derates help minimize average downtime.

Plant Availability

(%)

Our long-term target is to have our plants available 90 per cent of the time.

In 2006 our plants were available

89%

of the time.

The 51 MW Ghost hydro facility in Alberta

Major Maintenance Spending & Lost GWh

Major maintenance spending is a significant cost in our business. In 2006, we outperformed the spending targets we set while reducing the time our equipment was down for maintenance.

We have achieved a more predictable major maintenance spend.

Our highly specialized team of technical experts has developed lifecycle plans for each of our generating facilities. Lifecycle planning means we can be more predictive with our scheduling, drive down costs and make wise investments of capital in our equipment. The goal is to spend dollars more efficiently without sacrificing plant performance, not just for today but over the entire life of the asset.

technical expertise,

We are one of the largest emitters of greenhouses gases in Canada. It's the nature of our business and the product we sell.

We are reducing our environmental footprint by:

- Making efficiency upgrades at plants.
- Increasing investment in renewables.
- Participating in offsets and emissions trading markets.
- Investing in emerging technologies.

environmental leadership,

Our commitment to the environment is reflected in our sustainable business practices.

To learn more about our sustainable development efforts, please turn to page 22.

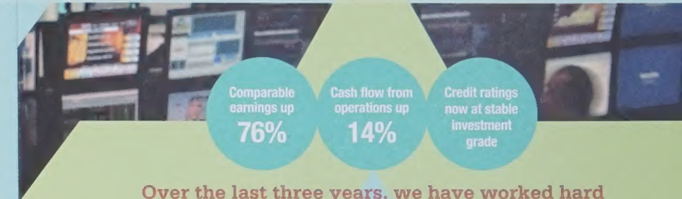
Catherine Latchford, Emerging Markets Manager and Deanne Carson, Director Marketing, are turning by-products like fly-ash into profits.

Our focus is on customers and profits, not just production.

We strive to maximize margins and manage our portfolio risk on a real-time and medium-term basis. In some cases this means we might decide to 'buy power' versus 'make power' because the market price is cheaper. On a longer-term basis, we'll maximize the value of our portfolio by making strategic decisions about the assets in which we'll invest and the assets that we'll buy, build, hold or divest.

portfolio management,

Our integrated asset teams of operations and commercial people work together to manage TransAlta's portfolio.



Comparable earnings up **76%**

Cash flow from operations up **14%**

Credit ratings now at stable investment grade

Over the last three years, we have worked hard to improve our financial position.

financial discipline and flexibility.

Looking ahead, we will evaluate investments on their financial merits to ensure that projects getting the green light support our 10 per cent return on capital employed objective, yield the greatest cash flow, are accretive and support our investment-grade credit ratings.

TransAlta employee David Chauvin is a Mechanical Technician for the 68 MW Windsor-Essex cogeneration plant in Ontario.

IN MILLIONS OF CANADIAN DOLLARS
except per common share data

financial highlights

Year ended Dec. 31	2006	2005	2004
Revenues	$ 2,796.5	$ 2,838.5	$ 2,586.2
Net earnings	$ 44.9	$ 186.3	$ 169.2
Comparable earnings[1]	$ 233.8	$ 161.3	$ 127.1
Cash flow from operations	$ 489.6	$ 619.8	$ 591.2
Per common share data			
Net earnings	$ 0.22	$ 0.94	$ 0.88
Comparable earnings[1]	$ 1.16	$ 0.82	$ 0.66
Dividends	$ 1.00	$ 1.00	$ 1.00
Ratios			
Cash flow to interest coverage (times)	5.5	4.7	4.3
Cash flow to total debt (%)	26.2	23.0	19.1
Debt to invested capital (%)[2]	40.9	43.9	46.4
Return on capital employed (%)	2.5[3]	7.1	7.6

1. Comparable earnings is not a defined term under Canadian generally accepted accounting principles (GAAP). Refer to the Non-GAAP Measures section on page 61 of the MD&A for a further discussion of comparable earnings.
2. Includes non-recourse debt.
3. Includes $153.6 million after-tax charge related to Centralia mine decision and $84.4 million impairment of the Centralia Gas facility. On a comparable basis, return on capital employed would be 8.3%.

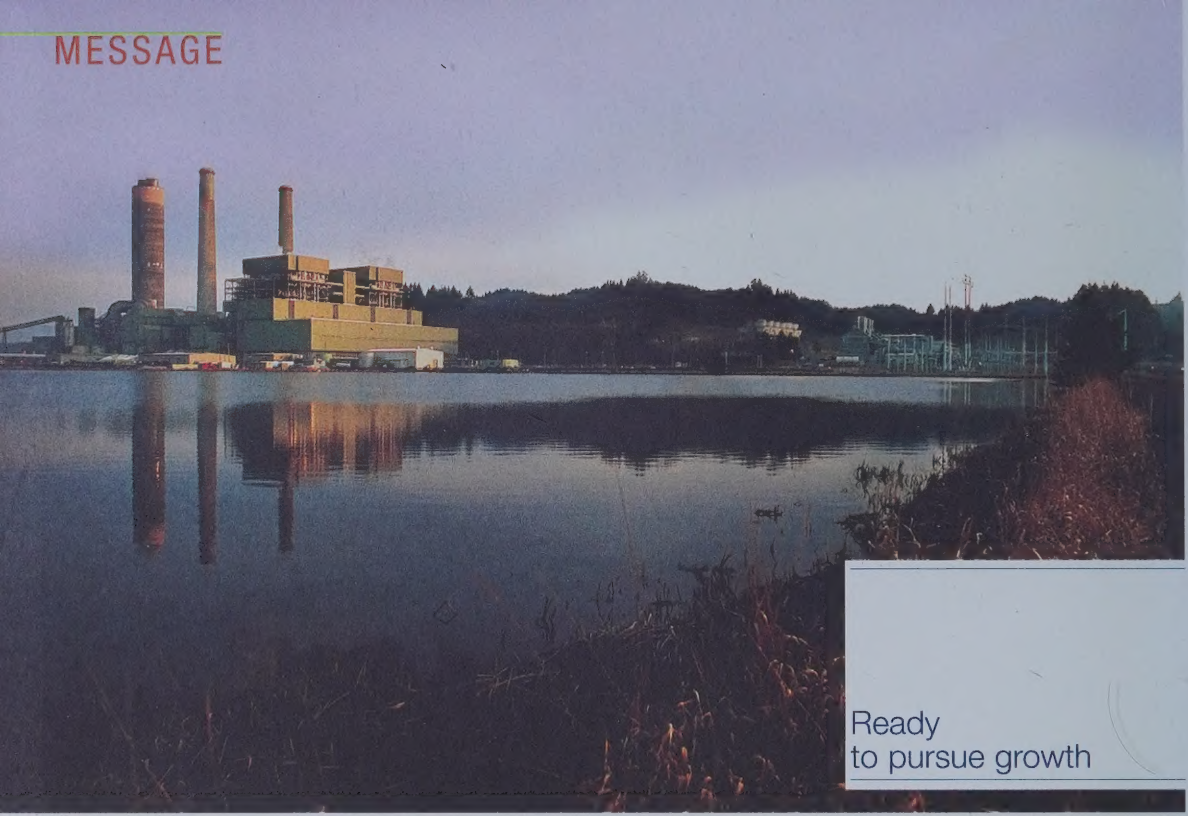
Alberta is experiencing strong economic growt
For nearly 100 years, we've been generating power in A
at our Sundance facility and beginning construc
to come online in 2011. Like Alberta, de

nomic growth driven by the global demand for hydrocarbons.
rating power in Alberta. In 2007, we'll meet this demand by increasing capacity
eginning construction on Keephills 3 – a 450 MW supercritical facility scheduled
. Like Alberta, demand for electricity continues to grow in each of our markets.

STEPHEN G. SNYDER
President & Chief Executive Officer

a world of opportunity

Our team is highly focused on delivering disciplined and steady capacity growth over the next five years.



Ready to pursue growth

Three years ago I laid out some tough goals for our company. Our industry had just come through a difficult period – bankruptcies, price collapses, massive capacity over-builds. We needed to get our company into fighting shape so we could be ready when the industry's next growth wave began.

OUR ACHIEVEMENTS

For the past three years, we have outlined our operating and financial goals (see page 13). Since 2004:

- comparable earnings[1] have grown 76 per cent,
- cash flow from operations has increased 14 per cent,
- credit ratings have improved to stable investment grade,
- plant availability has remained high at 89 to 90 per cent,
- contracting objectives have been achieved and
- total shareowner return over the three-year period has been 67 per cent versus the Toronto Stock Exchange Capped Utility Index total shareowner return of 61 per cent.

TOTAL SHAREHOLDER RETURN
($) cumulative value of $100 investment assuming reinvestment of dividend

Today your company is in great shape. Market conditions are improving. And we can punch above our weight as we showed in 2006, where we faced a number of challenges that tested our team. They met each one with resilience and dedication. There's an employee story behind each event. Each story illustrates the values that drive our success: a focus on the fundamentals and the ability to achieve results through disciplined action, teamwork and a commitment to safety.

One such event occurred in August at Unit 2 of our coal-fired Centralia plant. We had to shut down the unit after a blade failure in a five-year-old low-pressure turbine. Typically these blades last about 30 years so the shutdown was totally unexpected. Our repair teams acted quickly and worked with our procurement specialists to source new blades despite industry shortages. They knew they had to get the plant up and running as fast as possible. The team effort worked. We could have been off-line for months, but 40 days after the event, Unit 2 was producing power. We also completed a precautionary check on the Centralia Unit 1 blades. They checked out fine.

This quick response by our teams contributed to a record gross margin[1] of $1.4 billion in our generation business, a $41 million increase over 2005. Also contributing to these results was our high availability from our Alberta coal-fired plants, averaging 89.6 per cent for the year versus 88.1 per cent in 2005. Strong pricing in Alberta and increased production from our Alberta-based merchant operations also supported the strong operating results.

1 Comparable earnings and gross margin are not defined under Canadian GAAP. Refer to the Non-GAAP Measures section on page 61 of the MD&A for a further discussion of comparable earnings and gross margin, including a reconciliation to net earnings.

OUR OPERATING & FINANCIAL MEASURES & GOALS

>AVAILABILITY AND PRODUCTION

Availability is a key factor in determining revenue in many of our contracts. Availability is the percentage of time a generating unit is capable of running, regardless of whether or not it is generating electricity. As plants need maintenance and occasionally break down, 100 per cent availability over an extended period of time is not achievable.

Production is also a significant driver of revenue in certain contracts. Production is the amount of electricity generated and is measured in gigawatt hours.

	04	05	06	Target
Availability (%)	89.2	89.4	89.0	90+
Production (GWh)	51,396	51,810	48,213	Increase

>CONTRACTS

Electricity prices vary hour-by-hour and year-over-year. To reduce our exposure to large swings in electricity prices, we contract a large percentage of our expected capability for terms of one year or more. The weighted average remaining life of our contracts is 12 years.

	04	05	06	Target
Contracted capability (%)	83	82	81	≧75

>MARGIN AND PRODUCTIVITY

Growing gross margin is essential to our success. We increase revenues by capturing market opportunities through higher contract pricing and in the spot market. Managing our fuel costs is also critical, although many of our contracts allow for the recovery of fuel through contract terms.

Managing our maintenance and administration costs is also essential to improving the bottom line. Productivity is measured as operations, maintenance and administration (OM&A) expense per installed megawatt hour (MWh). Our goal is to offset the impact of inflation on OM&A.

	04	05	06	Target
Gross margin ($/installed MWh)	18.62	19.74	20.35	Increase
OM&A ($/installed MWh)	7.53	8.16	7.93	Hold with inflation

>CAPITAL EXPENDITURES

Capital expenditures are investments in our business. We classify our capital expenditures as either sustaining or growth. Sustaining capital expenditures include investments in such things as equipment for our mines, new information systems and routine and major maintenance on our plants. Our goal is to make sustaining capital expenditures more predictable and in line with our long-range plans. Capital expenditures on growth are discretionary and will vary over time.

	04	05	06	Target
Sustaining ($ millions)	204	287	207	07 budget 320–340
Growth ($ millions)	142	42	17	Variable

>EARNINGS PER SHARE AND CASH FLOW

Earnings per share (EPS) is frequently used to measure a company's profitability. Our target is to increase EPS on a comparable basis annually.

Cash generated from operations is used to maintain our equipment, meet our debt repayment obligations and pay dividends to our shareholders. Our goal is to generate cash in excess of these obligations so we may invest in growth projects, further reduce debt, or return it to shareholders. Our previous target was to generate cash from operations of $550 – $650 million. We achieved that goal and accordingly have increased our target for 2007.

	04	05	06	Target
Earnings/share (comparable basis) ($)	0.66	0.82	1.16	Increase 6–10% annually
Cash from operations ($ millions)	591	620	675[1]	650–750

1 This includes the $185 million receivable of Jan. 2, 2007 due to timing of November 2006 sales.

>INVESTMENT RATIOS

Financial ratios measure our overall financial strength and flexibility. We focus on cash flow to interest, cash flow to total debt, and debt to invested capital. Credit rating agencies use these ratios when evaluating the company. Our goal is to maintain the equivalent of BBB+ credit ratios, which is considered to be a strong investment grade.

We also measure returns to our shareholders and investors two ways: return on capital employed (ROCE) and total shareholder return (TSR). ROCE is a measure of the efficiency and profitability of capital investments. TSR is the total amount returned to investors over a specific holding period and includes capital gains and dividends.

	04	05	06	Target
Cash flow to interest (times)	4.3	4.7	5.5	4.2
Cash flow to total debt (%)	19.1	23.0	26.2	28.0
Debt to invested capital (%)	46.4	43.9	40.9	48.0
ROCE (%)	7.6	7.1	2.5	≧10%
TSR (%)	3.3	47.6	9.2	≧10%

The 245 megawatt (MW) Southern Cross power plant in Western Australia is strategically located near our customers to help meet their growing demand for electricity.

A different operations challenge, however, negatively impacted our 2006 results: our decision to stop mining at our Centralia coal pits and to transition the plant to 100 per cent imported Powder River Basin (PRB) coal. This was our toughest decision in recent history. In addition to the financial implications, we had to tell nearly 600 employees they no longer had jobs. I can't describe how difficult and emotional that was. However, since the existing pits had reached the end of their economic lives, the facts were inescapable: we had to stop mining.

Our decision to use 100 per cent PRB coal at our Centralia coal-fired plant brings new challenges and opportunities. Historically, our units were designed to burn only 30 per cent imported coal. However, because imported PRB coal has a higher BTU content than our local coal, we will have to reconfigure our units. Until we make these necessary changes, we'll have to derate the plant (produce less power) to protect the equipment and maintain safe, reliable operations.

Once we get back to higher operating rates, we'll be able to generate more power with less coal in the future.

So, how did we do in 2006?

FINANCIAL RESULTS

Excluding one-time events, comparable 2006 earnings were $233.8 million or ($1.16 per share) compared to $161.1 million ($0.82 per share) in 2005, a 42 per cent increase in earnings per share. Our comparable earnings reflect the underlying strength of our asset portfolio as well as ongoing earnings from our energy trading business.

Including one-time events, TransAlta reported GAAP earnings of $44.9 million ($0.22 per share) versus $186.5 million ($0.94 per share) in 2005. Included in 2006, GAAP earnings were major one-time after-tax charges of $153.6 million ($0.76 per share) for the writedown of the Centralia mine assets and related costs, and $84.4 million ($0.42 per share) due to changes in our future market assumptions requiring the financial impairment of our Centralia gas-fired plant. These were partially offset by a $55.3 million ($0.28 per share) gain related to prior year tax

rate changes. Net earnings for 2005 included a one-time after-tax gain of $12 million ($0.12 per share) and $13 million ($0.07 per share) resulting from a tax settlement on a deferred receivable.

For our shareowners, these 2006 results delivered total shareowner return of nine per cent. This is on top of 48 per cent in 2005. On a comparable earnings basis, ROCE was 8.3 per cent. While below our 10 per cent long-term ROCE goal, I believe our decision to stop Centralia mining, our productivity progress, as well as our future growth initiatives position us to meet and sustain our total shareowner return and ROCE goals in the years to come.

Long-term investors in TransAlta know how much we value cash flow. In 2006, our operating cash flow increased to $675[1] million, up from $620 million in 2005. We used this cash to maintain our plants ($207 million) and make required debt repayments ($51 million). The remaining free cash was used to pay dividends to shareowners ($121 million) and distributions ($74 million) to subsidiaries' non-controlling interest holders. At the end of the year, we still had $217 million in cash remaining which we will reinvest in our business.

1 2006 cash flow includes a $185 million receivable received Jan. 2, 2007 due to timing of collection of November 2006 sales.

OPERATING RESULTS

I'm especially proud that our teams stayed focused on essential, day-to-day operating activities. Our ability to block and tackle each day ensures that our earnings will remain strong even in the face of large-scale, one-time events. Below are just a few examples of how our teams generated strong earnings by focusing daily on the "small stuff":

Our **ENERGY TRADING** business turned in an outstanding performance. Their views on market and pricing trends were superbly analyzed. The result – gross margins were $65.7 million compared to $56.9 million in 2005. We see increased potential for the electricity trading business as the market matures and becomes even more liquid. In 2007, we are raising our annual run rate expectation to $50 – $70 million of gross margin from this business, up from the $30 – $50 million we had been expecting.

MAJOR MAINTENANCE planning is paying off. We outperformed our annual targets for spend and outage duration during the year, while achieving our availability goals. We spent a total of $140 million in 2006, 40 per cent of which was expensed. We have now reached our objective to stabilize this ongoing expenditure in the $150 – $175 million per year range – one year ahead of plan. Outage duration was only 2,325 GWh compared to the 2,818 GWh originally budgeted.

OM&A decreased year-over-year by $14.7 million. On an OM&A per gross installed MWh basis, OM&A was $7.93 in 2006 versus $8.16 in 2005. This is strong performance in the face of inflationary pressures. Our focus now is to sustain these gains in the years ahead.

Our **FINANCE** team met our year-end goal to certify that we are Sarbanes-Oxley Act compliant. News stories of how much work is required to achieve this milestone are not exaggerated and our team tackled this job efficiently and effectively. They also reduced interest expense by $20 million due to lower debt levels and favourable settlements of net investment hedges.

READY, STEADY, GROW

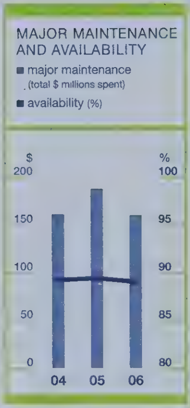
In my report last year, I introduced you to our Four Pillars of Performance: Operational Excellence, Plant Maintenance, Lifecycle Planning and Portfolio Management & Growth. Collectively, these pillars create our sustainable competitive edge and position us to steadily grow our capacity, earnings and cash flow.

OPERATIONAL EXCELLENCE

Our goal is to sustain reliable operations at optimal costs in our generation plants and coal operations. We have maintained high fleet-wide availability at 89 to 90 per cent levels. To do this, our operations and engineering teams systematically assess plant maintenance requirements. They have the skills and resources to be flexible and act promptly if any problems emerge. We conduct preventative maintenance between planned outages to further sustain reliability. As a result, our unplanned outage and derates now average only six per cent per year. That's strong performance in our industry and with our plant mix.

Production rates and costs at our Alberta coal mines remain relatively predictable and stable, despite the volatility and price inflation in the mining industry. Investments we'll make in 2007 on new 400-ton trucks will reduce our coal-handling costs by the end of 2008. And of course, our decision to source PRB coal at Centralia will dramatically reduce those coal costs starting around the middle of 2008.

When it comes to productivity we'll take big breakthroughs when they come. But our focus is on



The 259 MW Chihuahua plant in Mexico during a maintenance outage.

doing every task slightly better and safer. Our goal is to offset inflation on a per megawatt hour installed basis. To support this initiative, we have linked compensation to cost management. We're investing in technology and developing more efficient workforce strategies to reduce staff costs. The productivity focus extends right across the company. In 2007, I will operate with three fewer senior direct reports than I did in 2006. Corporate overhead costs will be challenged just as aggressively as every other cost in the company.

You know from past letters that I believe operational excellence is as much about safety as it is about making availability targets, reducing our costs and minimizing our environmental footprint. Our goal throughout the company is to achieve a Target Zero incident record. In 2006, we did not perform as well as in 2005. Our combined employee and contractor injury frequency rate for the year was 1.95 versus 1.41 the previous year. We must do better. Our objective is to make everyone in the company aware of incident prevention and to look out for each other. I expect to report better progress to you in 2007.

PLANT MAINTENANCE

We must maintain our asset base of $5.5 billion. Our goal is to drive up the profitability of our current fleet of assets while installing the systems and maintaining the discipline required to extract top performance from our future fleet.

Depending on the technology, our plants must have periodic major maintenance every two to four years. These outages cost as much as $40 million for labour and components and require shutdowns as long as six weeks. That's a big revenue loss. Our success is measured by extending the intervals between major maintenance outages and completing maintenance work as quickly as possible, without compromising plant availability, reliability, and safety.

Over the last couple of years, we have gained very deep asset knowledge and developed detailed maintenance plans for each facility. We have made a lot of progress in moving our coal fleet from a two- to three-year major maintenance interval. This transition will be completed by the end of 2007. It will result in fewer major outages, lower spend over the life of the asset and turn more megawatts into incremental gross margin. We are deploying this same discipline to optimize spending on our gas plants. We want to run these longer between major maintenance outages.

As a result of all these efforts, the predictability of our major maintenance program has increased and the level of maintenance spending has declined.

LIFECYCLE PLANNING

Like a car, every generation plant over time develops different operating characteristics and maintenance needs. We strive to find the "sweet spot" for each plant – to spend just enough money and not a cent more to extract the full value over its lifetime. Last year, I told you how we collect fleet-wide data on equipment and operating assets so we can gauge

how each asset in our portfolio will perform over its life. Our teams completed this work in 2006.

Now we can make timely, economical decisions about which plants need to be retired, which require capital to extend their useful lives, and which plants we should expand. Our success will be measured by the hundreds of millions of dollars we expect to save in reduced capital spends over the life of our fleet. While our power purchase arrangements don't begin to expire until 2017, we are already hard at work assessing the best long-term options for our Alberta fleet.

Our analysis supports the merits of adding approximately 50 MW to our coal-fired Sundance 4 facility. With peak electricity demand in Alberta growing at approximately five per cent per year, the modest $50 million we will invest in this Sundance uprate will allow us to add incremental production that will generate attractive future returns. We expect this uprate to be completed by the end of 2007.

We also continue to focus on key strategic supplier partnerships. These give us more reliable access to materials and components, savings due to economies of scale in purchasing and a continuing source of technical expertise that we can build on over the years.

PORTFOLIO MANAGEMENT & GROWTH

Through Portfolio Management, we are guided to make investment decisions that maintain the strength of our diverse portfolio of generation assets and contracts. In the immediate and medium term we must optimize our risk reward ratios whenever we make power purchase versus production decisions and in procuring fuel. We optimize our long-term risks and returns when we decide which assets we will buy, build, continue to hold or choose to divest.

Our portfolio of approximately 8,800 MW of generating assets is diversified by geography, fuel type, technology and contractual status. We operate in four countries: Canada, the United States, Mexico and Australia. We are 59 per cent coal-based, 28 per cent natural gas and 13 per cent hydro and renewable energy. Our technologies include conventional and supercritical coal-fired plants; combined cycle and peaker gas plants; cogeneration plants; and hydro, wind and geothermal plants. We have bilateral contracts with cogeneration partners and short-, medium- and long-term contracts with other creditworthy wholesale customers.

We manage this portfolio to reduce our earnings volatility and protect our cash flows. Our lifecycle planning models allow us to plan investments in existing and new assets over their expected asset lives. Our long-term strategic supplier contracts support our portfolio management. Our energy trading operations track record proves that we have a strong understanding of market fundamentals.

our markets – 2006

We see opportunity for growth in our existing markets where we have the expertise in buying, building and managing plants. Our market diversity and varied fuel mix allow us to approach these opportunities in a prudent, disciplined manner.

ALBERTA – 58%
- Small, deregulated market – peak load of 9,600 MW
- Peak demand growing at 4.7% per year compressing reserve margins
- Long term, oil sands and clean coal technology provide growth opportunities.

ONTARIO – 8%
- Large, hybrid market – peak load of 27,000 MW
- RFP driven market
- Demand growing at 3.8%
- Short-term opportunities in renewables

UNITED STATES – 25%
- Large, hybrid market – peak load of 28,300 MW
- Participate mostly in the Pacific Northwest
- Demand growing at approximately 1% per year
- Opportunities for expansion of geothermal assets

MEXICO – 6%
- Large, fully regulated market – peak load of 32,400 MW
- Strong demand growth at 4.8% per year
- Opportunities for acquisitions and new gas development

AUSTRALIA – 3%
- We limit ourselves to a niche market, doing cogeneration projects with resource companies in Western Australia.
- Our customers' power needs are growing as demand from Asia for natural resources increases dramatically.

Percentages above represent installed capacity in regions.

Our growth plans include the 53 MW uprate at the 2,020 MW Sundance plant in Alberta, the 450 MW Keephills 3 supercritical coal-fired plant in Alberta and a 75 MW wind farm in New Brunswick.

We have a long-term rail transportation agreement with BNSF Railway Company to deliver sufficient coal to meet annual fuel requirements at our Centralia coal-fired plant. BNSF is constructing additional track, as shown here, to increase its coal-carrying capacity.

We use this market intelligence to make both short-term production decisions and long-term investment decisions.

I also remind you that our goal is to contract at least 75 per cent of our plant availability in order to reduce our exposure to price swings in the market. In 2006, we signed contracts with the Ontario Power Authority to supply an average of 400 MW from our Sarnia cogeneration plant for approximately five years. We also met our re-contracting targets for our Centralia coal-fired plant. We signed contracts extending from 2007 to 2009 for approximately 900 MW per year of our capability at an average price of US$45 to $55 per MWh. This is a significant uplift from the US$30 per MWh of the original contracts.

This overall ability to optimize our portfolio is key to understanding our growth strategy.

WHAT YOU CAN EXPECT IN 2007

GROWTH INITIATIVES

Our team is highly focused on delivering disciplined and steady capacity growth. But, we will maintain our targeted credit ratios and stay with the technologies and geographies we know best. We will balance our greenfield development (building of new plants) with brownfield expansions (existing asset expansion) and acquisitions. Our goal is simple and achievable: deliver five per cent average annual capacity growth over the next five years.

Whether it is a single asset or a portfolio of assets, each new project and transaction will be put through our comprehensive capital allocation process. It screens and ranks each investment alternative against criteria such as market, size of investment, ownership, technology and operations, commercial contracts, portfolio effects and environmental risks. And of course financial metrics are analyzed in detail. It's a tough screen.

We are already off to a solid start to meet our growth objectives. In addition to our previously announced plans to expand our Sundance plant, we announced in January 2007 that we would build a new 75 MW wind facility. It will supply electricity to New Brunswick Power under a 25-year long-term contract. The wind farm is expected to cost $130 million and to be in operation by the end of 2008.

In February 2007, we announced our decision to expand our Keephills plant by 450 MW using super-critical technology. This will be a joint venture with EPCOR, our partner in Genesee 3. Commissioned in 2005, it was the first supercritical pulverized coal plant to be built in Canada. Because this type of facility burns coal more efficiently than conventional coal plants, it has fewer emissions and delivers more megawatts per BTU. The total cost, estimated at $1.6 billion, will be shared equally by EPCOR and TransAlta. Once commercial in 2011, Keephills 3 along with Genesee 3 will be among the most advanced coal-fired plants in the world. These additions will allow us to decommission our oldest coal plant, Wabamun 4, as planned in 2010.

Additional investment opportunities exist in Alberta from the economic expansion related to the oil sands. In Australia the explosive world demand for commodities provides opportunities. New generation investments will be needed in Eastern Canada, the Western United States and Mexico to meet steadily growing demand. Building on the lessons from our past, I am confident that we can execute successfully on our growth goals.

online

To learn more about our energy trading and marketing business, visit www.transalta.com

CENTRALIA CHALLENGES IN THE TRANSITION TO PRB COAL

We are implementing a plan that will result in more predictable and lower coal costs for the Centralia coal-fired power plant. In November 2006, we secured a long-term rail transportation agreement with BNSF Railway Company to deliver sufficient coal to meet our annual fuel requirements and to give TransAlta access to multiple mines for supply flexibility.

We also executed medium-term coal supply contracts. The contracts allow us to keep our costs predictable and in line with market prices. Given that there are many suppliers in the PRB and we have a long-term rail agreement in place, we are confident we can continually contract ideal coal mixes for the life of the plant.

In 2007 and 2008, we expect to invest CDN $50 – $60 million of capital in our on-site rail capacity to streamline the handling, unloading and stockpiling of PRB coal deliveries. This investment will be split evenly between the two years. When complete, we will be able to meet our full fuel requirements for the Centralia coal-fired facility.

Also in 2007, we will work diligently to reconfigure the Centralia coal-fired plant to be able to fully use PRB coal. Over the next two years, we estimate capital spending of approximately CDN $50 – $60 million on Centralia coal-fired plant specific modifications, split evenly between 2007 and 2008.

As discussed earlier, until we complete our reconfiguration, the higher heat content PRB coal forces us to temporarily derate our Centralia plant. Our current estimate is that the 2007 revenue loss from derating the plants is, unfortunately, about equal to our fuel cost savings derived from our new sourced coal. That will hold us back in 2007, although we will benefit from higher contracted prices on our Centralia coal-fired electricity sales.

The good news is that we'll get the benefit of the full cost savings by mid-2008, and more importantly, every year after that. Meanwhile, in 2007, our engineering and operation teams are focused on minimizing any derates and getting our new equipment installed as quickly as possible.

ENVIRONMENTAL LEADERSHIP

Your company has aggressively invested in sustainable development for over 10 years. We did that not only because it was our obligation and the right thing to do for the environment, but also because it made business sense to us.

A founding member of the Canadian Clean Power Coalition, our goal is to cost-effectively reduce our environmental footprint. Public opinion, public policy and our industry are catching up to our leadership. That's a good thing. It's also why these efforts will continue to be a cornerstone of our strategy.

Our environmental management strategy includes:

- participating in policy development with non-governmental organizations (NGOs) and all levels of government to ensure clear and sensible rules are established and compliance costs are acceptable to our customers,
- investing in renewable energy such as wind and geothermal, now four per cent of our portfolio, with a long-term goal of achieving 10 per cent of our capacity from renewables,
- acquiring and trading offsets of carbon and other emissions, an area where we are recognized innovators and leaders,
- management of environmental risk using ISO-14001-based management systems and market mechanisms,
- investing in advanced technologies such as SO_2 scrubbers at our Centralia coal-fired plant and in supercritical boiler technology at our Genesee 3 plant and Keephills 3 project and
- testing new enhanced activated carbon injection technology at our Sundance plant that we believe will reduce mercury emissions 70 per cent by 2010.

We have made meaningful progress on managing our impact on the environment. Since 2000 we have reduced:

- sulphur dioxide intensity by 64 per cent,
- nitrogen oxide intensity by 16 per cent and,
- greenhouse gas emission intensity by 4 per cent.

In 2006, we were recognized by the Dow Jones Sustainability Index for the eighth consecutive year. Within the annual report, pages 22-23 are dedicated to our sustainable development report to investors. We are proud of these achievements and we will continue to strive for even better progress in the future.

Dow Jones Sustainability Indexes
Member 2006/07

OUR TEAM AND OUR MISSION

TransAlta is unique. We are a wholesale generation and marketing company that pays investors a dividend. We operate a diversified and highly contracted portfolio of generation assets. And, we have stable investment-grade credit ratings.

Our teams drive our success. In 2006, unusual and large-scale events challenged us. The men and women of TransAlta responded quickly and effectively. In 2007, you can expect the same dedication to results.

standing left to right Mike Williams, Executive Vice-President Human Resources & Communications, Ken Stickland, Executive Vice-President Legal, Linda Chambers, Executive Vice-President Generation Technology, Richard Langhammer, Executive Vice-President Generation Operations *sitting left to right* Brian Burden, Executive Vice-President & Chief Financial Officer, Tom Rainwater, Executive Vice-President Corporate Development & Marketing

Each month, our executive team checks our progress against our short-term goals and our five-year plan. We revisit our strategy with our Board of Directors at each meeting. If regulations change or opportunities arise, we can change our strategy to meet the shifts. Our Board continues to provide superb governance and management guidance. They actively participate in our strategy development. They set and monitor our overall risk profile. Their stewardship includes setting the highest standards for ethical behaviour.

Today, TransAlta is fit and ready to pursue value growth opportunities. We are located in good geographies with tightening reserve margins. We have the assets, technology and expertise to optimize a diversified portfolio. We have the lifecycle management systems and strategic supplier relationships to manage a more predictable capital spend. We are environmental leaders and we proactively mitigate our impact on the environment. We have the balance sheet strength and liquidity to support commercial activities and sustainable growth objectives.

As a shareowner and as TransAlta's leader, I am very proud of this company. We were severely tested by industry events over the last few years and emerged in strong shape. I want to sincerely thank each and every one of our employees for their unfailing efforts day-in-and-day-out to meet our goals. If you come to our shareholder meeting this April in Calgary, you can meet many of them in person.

We will continue to be tested. The environment looms big for us. We must stretch our resources and our ideas to do more. New technologies must be chosen. Growth decisions must be made. Fortunately, TransAlta's employees have the spirit, the resilience and the dedication to succeed in these upcoming challenges. We will continue to strive to improve and do better than anyone else in our industry.

STEPHEN G. SNYDER

President & Chief Executive Officer
February 27, 2007

Connecting with communities

TransAlta's connection with communities grew this year through efforts to deepen existing partnerships and develop new ones. Over $5 million was contributed to organizations in communities where our employees live and work.

With a significant portion of our operations in the Edmonton area, we partnered with The City of Edmonton to showcase the artistic wealth of the city.

Through the **TRANSALTA FESTIVAL CITY** grant program we will build artistic capacity in the greater Edmonton area. Managed by the Edmonton Arts Council, the program helps position arts organizations for growth. Organizations can use grants to develop better festivals by adding new artistic resources or seeking mentoring and consulting services.

At the same time, the **TRANSALTA FESTIVAL CITY IN A BOX** program acknowledges the strength of the city's arts community in achieving tourism and economic development objectives. Through this program, samplings of Edmonton's arts community are packaged "in a box" to entice visits by tourists and conventions. In 2006, the **TRANSALTA FESTIVAL CITY IN A BOX,** operated through the Edmonton Economic Development Authority, was featured prominently at an Alberta Days event staged by the Government of Alberta with the Smithsonian Institute in Washington, D.C.

We believe community investment partnerships are more than financial commitments. Engaging our employees, including TransAlta's senior executives and retirees, is an integral element of our successful partnerships. Including the contributions of our TransAlta Community Transformers **(TACT)**, our employees volunteered over 12,300 hours in support of company and community-led programs. In 2006, we created the Executive Connection program, which encourages our Executive Vice-Presidents to become involved on community boards, lending their experience and expertise in support of a variety of causes. TransAlta's retiree group, Projects Organized With Energetic Retirees **(POWER)**, took on a range of projects last year including growing vegetables for the Calgary Inter-faith Food Bank, knitting and donating items to local hospitals for children and participating in the Tim Horton's Children's Ranch fall clean-up.

Our relationship with aboriginal communities grew through our participation in Traditional Land Use studies conducted by the Paul and Blood First Nations. Productive dialogue about our operations continues to be a focus, with regular communication meetings with the Paul Band and the creation of a Transmission Advisory Committee, including representatives from the 13 First Nations where we have operations.

TransAlta's community investment focuses on a small number of initiatives where we can have the most meaningful impact over the long term.

above Festival performers from the TransAlta Festival City in a Box program

left TransAlta retiree, Brian Peters, harvests the POWER garden for the Calgary Inter-faith Food Bank.

online To learn more about our community investment programs, visit www.transalta.com

Sustainability remains one of the key components in how we conduct our business

TransAlta has a long history of taking on the challenges of sustainable development. Since the 1990s, we have been focused on building a sustainable company, balancing the economic, environmental and social implications of our business decisions. Today, sustainability remains one of the key components in how we conduct our business.

We strive to:

- operate with the highest standards of safety,
- reduce the environmental impacts of our operations and develop long-term plans to achieve more aggressive environmental standards,
- recruit and retain the best employees,
- consult with people impacted by our operations and
- support communities where our employees live and work.

Every year, we aim to improve the accuracy and completeness of the reporting of our sustainability performance to stakeholders. In 2006, we reviewed our processes and controls relating to the measurement, calculation, consolidation and reporting of some of our key sustainability data. We will have these reviewed by an external party in 2007.

Voluntary reporting is only one of the ways TransAlta reinforces our sustainable development commitment. We openly report on economic, environmental and social performance because it encourages us to accurately and comprehensively assess the year's performance. Voluntary reporting illustrates how sustainable thinking is part of our business – influencing the decisions we make and the actions we take.

ECONOMIC SUSTAINABILITY

We believe we have a sustainable business model. Our diversified portfolio of generating assets combined with our technical and commercial expertise means we have the right components to deliver balanced, sustainable and profitable growth for our shareholders.

In 2006, our total shareholder return was nine per cent. This was in spite of incredible business challenges such as the decision to stop mining at our Centralia coal mine and transition to PRB coal and the impairment of the Centralia gas-fired asset. Excluding these events, comparable earnings were up 41 per cent at $1.16 per share compared to $0.82 per share in 2005. Cash flow increased to $675 million[1], up from $620 million in 2005. We use this cash to maintain our plants, pay dividends to our shareholders, pay down debt and reinvest in the business.

Looking forward, we are pursuing growth opportunities in the markets and geographies we know. We have announced plans to build a 75 MW wind farm in New Brunswick, add 53 MW of additional capacity at our Sundance facility and proceed with building the next supercritical coal-fired plant in Alberta – Keephills 3.

ENVIRONMENTAL SUSTAINABILITY

We remain committed to reducing the environmental impacts of our operations. In addition to our active participation in policy discussions that will affect our industry, we have a comprehensive environmental strategy:

- find internal efficiencies at plants,
- increase our investment in renewables,
- continue to build our offsets portfolio and emissions trading strategy and
- support development of cleaner emerging generation technologies.

This strategy has been in place for several years to reduce environmental risk and deliver competitive opportunities. We use the internationally recognized ISO-14001 standard to manage our environmental risk.

While we have made some meaningful progress in reducing our impact on the environment, we know that we must develop long-term plans to ensure we achieve the aggressive environmental

1 2006 cash flow includes a $185 million receivable received Jan. 2, 2007 due to timing of collection of November 2006 sales.

Danielle Stuart, Environmental Specialist and Don Wharton, Director Sustainable Development, help balance the economic, environmental and social implications of business decisions.

standards of the future. We are prepared for new environmental regulations and believe our ongoing stakeholder engagement and our early, proactive and voluntary action will pay off over the long term.

SOCIAL SUSTAINABILITY – WORKPLACE SAFETY AND COMMUNITY RELATIONS

Our goal is to provide a safe and healthy workplace for all employees and contractors. Our Target Zero initiative is designed to drive improvements in safety, health and environmental performance. Under Target Zero, a leadership committee meets monthly to identify leadership actions and develop proactive work plans to improve our performance through standard processes and company-wide environment, health and safety initiatives.

Regrettably, in 2006, there was a contractor fatality at one of our facilities. We have completed our internal investigation and are fully cooperating with Workplace Health and Safety as they conduct their investigation. We remain focused on finding out what happened and will do whatever we can to prevent tragedies like this from happening in the future.

We have a strong base of internal policies governing how we conduct our business. TransAlta employees fulfill these policies while upholding the highest level of ethical conduct and meeting responsibilities as good corporate citizens.

Since our operations affect many different individuals and groups of people, public consultation is a significant part of our business. Through open houses, one-on-one meetings and other engagement strategies, we listen and respond to stakeholder concerns about development, ongoing operations and decommissioning activities. Meaningful relationships with affected parties enable us to continue operating our facilities. As we decommission our Wabamun facility and begin construction on the 450 MW Keephills 3 power plant, we will continue to engage local government officials, local businesses, regulatory agencies and other stakeholders from the surrounding communities.

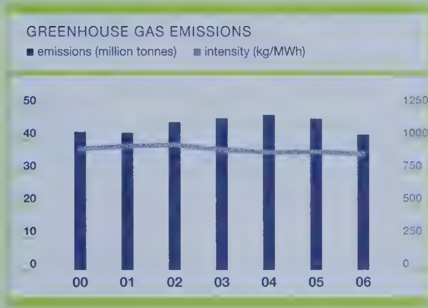
Community investment is part of our social commitment. TransAlta is dedicated to helping sustain vibrant and healthy communities and the environment for today and for tomorrow. For more information on our community investment activities, turn to page 21.

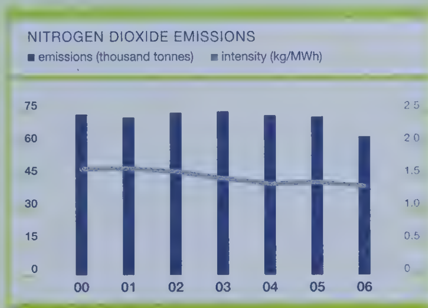
The investment community is increasingly concerned with how companies are managing environmental and social pressures and how this risk management translates into economic performance. We believe such factors will become another competitive differentiator for TransAlta. That is why we continue to speak with the investment community regarding our progress in this area. We believe sustainability is an integral part of our business.

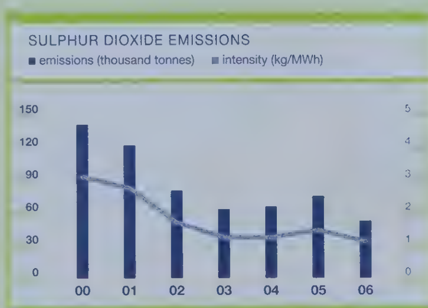
online

To learn more about TransAlta's sustainability efforts, visit our website at www.transalta.com

In our business, air emissions associated with generating electricity are a key environmental issue. The following charts* illustrate how we are managing the primary emissions associated with our business:







* *Data above represents only those facilities for which TransAlta holds the operating permits.*

Approaching business oversight from economic, environmental and social perspectives makes good business sense.

DONNA SOBLE KAUFMAN
Chair of the Board

As you see in this annual report, TransAlta achieved strong operational and financial results in 2006 while working through significant business challenges. This performance reflects the resilience of your Company. On behalf of the Board of Directors, I congratulate the TransAlta management team and the dedicated employees across the company on a job well done.

During my time on TransAlta's Board, I have seen many changes in the industry, the company and shareholders' expectations. Throughout these changes, the Board has remained focused on building a sustainable company – a company that will continue to deliver profitable growth for you over time. To do this, your Board is fully engaged in the development of the strategic plan, has established the appropriate risk parameters, has monitored progress and has demanded results. We have ensured TransAlta has operated in an ethical, economically rewarding and environmentally and socially responsible manner.

The Directors of TransAlta recognize that corporations are expected to deliver more than positive economic performance. Corporations that factor the social and environmental risks and benefits are recognized by society as doing the right thing and by investors for delivering a sustainable business model. I am pleased to report your Company continues to be recognized for its efforts in approaching business from this perspective. For the eighth consecutive year, TransAlta has been listed on the Dow Jones Sustainability Index. This index represents the top 10 per cent of sustainable companies worldwide. We are very pleased to be included in this list not only for the honour, but also because these listed companies have been shown to consistently outperform others financially.

TransAlta's sustainable development performance is due in large part to the leadership of Dr. Bob Page, who retired from TransAlta in January 2007 to become the first TransAlta Professor at the University of Calgary's Institute for Sustainable Energy, Environment and Economy. On behalf of the Board, I would like to thank Bob for his tireless dedication to TransAlta's sustainability efforts.

Sustainable development and good governance contribute to corporate performance. Your Board is fully engaged in creating and maintaining shareholder value and dedicated to good stewardship of

the Corporation. During 2006, the Board and its committees devoted considerable time, effort and thought to assure that we maintain best practices in Corporate Governance.

Further, we have an annual two-day strategy session where we discuss the Corporation's strategic plan with our management team. This year a significant part of the discussion was focused on the Corporation's plans for sustainable growth.

With TransAlta's growth plans articulated, the Directors wanted a clear understanding of how management is assessing and addressing the risk associated with those plans. To facilitate this, the Board modified its previous committee structure to ensure more direct oversight on risk and the environment. Both the Audit and Risk and the Governance and Environment committees have clear mandates to carefully study their respective areas, review management's decisions and report to the Board regularly. Our Board believes these modifications will better align priorities and ensure environment and risk management issues are being diligently handled.

Our Board's commitment to maintaining a culture of the highest ethical and professional standards with sound corporate governance was recognized by *The Globe and Mail's Report on Business* report on corporate governance. For the fifth consecutive year, TransAlta has been ranked among the best governed corporations in Canada. Board composition is a major component in this determination. We have a highly qualified, independent Board, with members from various parts of the world. In addition to providing regional insight and expertise, each Board member brings both depth and diversity of experience to the table.

In July, we welcomed Dr. Martha Piper to our Board. An exceptional academic and scholar, Martha is an Officer of the Order of Canada, a recipient of the Order of British Columbia and has made extraordinary contributions around the world.

She was recently appointed a member of the Trilateral Commission – an international think tank focused on fostering closer cooperation among democratic industrialized areas of the world. Her experience as a senior university administrator and in international relations will serve the Board well.

As Chair, I very much appreciate the support of my colleagues on the Board for their wise counsel during what has been an extremely demanding year at TransAlta.

TransAlta's Board of Directors is convinced that approaching business oversight from economic, environmental and social perspectives makes good business sense. We recognize that our shareholders entrust this duty to us and we are determined to continue to earn this trust. The foundation we have built in the years leading up to 2007, both at the Board and operating levels, has positioned us to create profitable growth. As a Board, we have every confidence in TransAlta's management team and employees to deliver this for our shareholders.

Thank you for placing your confidence in us.

DONNA SOBLE KAUFMAN

Donna Kaufman

Chair of the Board

BOARD OF DIRECTORS

WILLIAM D. ANDERSON Director since 2003 and resident of Toronto, Ont. Mr. Anderson was President of BCE Ventures, a subsidiary of BCE Inc., from 2001 to 2005 and CFO of BCE Inc. from 1998 to 2000. He is a director of Bell Canada International Inc., the Four Seasons Hotels Inc., Gildan Activewear Inc. and MDS Inc. He is a member of the Institute of Chartered Accountants of Ontario.

STANLEY J. BRIGHT Director since 1999 and resident of Oxford, Maryland. Mr. Bright was Chair and CEO of MidAmerican Energy Company from 1997 to 1999 and President, CEO and Chair and CEO of predecessor companies from 1991 to 1997. He served as a director of MidAmerican Energy Holdings Company, a subsidiary of Berkshire Hathaway Inc., from 1999 to February 2006 and has been a director of MidAmerican Energy predecessor companies since 1987.

TIMOTHY W. FAITHFULL Director since 2003 and resident of Oxford, United Kingdom. Mr. Faithfull was President and CEO of Shell Canada Limited from 1999 to 2003, when he completed a 36-year international oil and gas career with the Royal Dutch/Shell Group. He is a director of Canadian Pacific Railway Limited, Shell Pension Trust Limited and AMEC plc in the United Kingdom. He is a council member of the Canada United Kingdom Colloquia and a trustee of the Starehe Endowment Fund (U.K.).

GORDON D. GIFFIN Director since 2002 and resident of Atlanta, Ga. Ambassador Giffin is a Senior Partner of McKenna Long & Aldridge LLP. He is a director of Bowater, Inc., Canadian National Railway Company, Canadian Imperial Bank of Commerce and Canadian Natural Resources Ltd. and Ontario Energy Savings Corp. He is a member of the Council of Foreign Relations, an advisory board member of the Canadian-American Business Council and serves on the Board of Trustees for the Carter Center in Georgia. Ambassador Giffin served as United States Ambassador to Canada from 1997 to 2001.

C. KENT JESPERSEN Director since January 2004 and resident of Calgary, Alta. Mr. Jespersen has been Chair and CEO of La Jolla Resources International Ltd. since 1998. He worked with NOVA Corporation for over 20 years in various management positions, including President of NOVA International. He is Chair of North American Oilsands Ltd., Chair and a director of CCR Technologies Ltd., a director of Matrikon Inc. and Axia NetMedia Corporation.

MICHAEL M. KANOVSKY Director since January 2004 and resident of Victoria, B.C. Mr. Kanovsky has been President of Sky Energy Corporation since 1993. He has been involved in investment banking and the oil, gas and power industries for over 30 years. He is a director of Accrete Energy Corporation, Devon Energy Corporation, ARC Energy Trust, Bonavista Energy Trust and Pure Technologies Inc.

DONNA SOBLE KAUFMAN Director since 1989 and resident of Toronto, Ont. Mrs. Kaufman is Chair of the Board of TransAlta Corporation. Mrs. Kaufman is a director of BCE Inc., Bell Canada and Telesat Canada. She is also a director of Historica, The Baycrest Centre, a Fellow of the Institute of Corporate Directors and a member of the Canadian Board of Advisors of Catalyst.

corporate governance

TransAlta's directors are experienced business leaders representing varied geographic and professional backgrounds, including business, finance, law and public service. On behalf of TransAlta's shareholders, the Board of Directors is responsible for the stewardship of the corporation, establishing overall policies and standards and reviewing strategic plans. In 2006, the directors met on 11 occasions, including one special meeting devoted exclusively to TransAlta's corporate strategy and direction.

After a detailed examination of the relationships between each of the directors and TransAlta, the Board determined that 10 of the existing 11 board members are independent, excluding only Stephen Snyder, President and CEO of the company. All of the members of each of the committees of the Board are independent. In 2006, the Board had three committees, which are briefly described as follows. Further detailed information with respect to TransAlta's approach to corporate governance is contained in the 2006 Management Proxy Circular.

AUDIT AND ENVIRONMENT COMMITTEE

The committee is responsible for reviewing financial reporting, financial controls, internal audit matters, financial risks inherent in the business and environmental risks and regulations affecting the Corporations's activities. This committee met 11 times in 2006. Committee chair: William D. Anderson. Members: Stanley J. Bright, Timothy W. Faithfull, Michael M. Kanovsky, Gordon S. Lackenbauer and Donna Soble Kaufman (as an ex-officio member).

HUMAN RESOURCES COMMITTEE

The committee is responsible for reviewing and recommending executive compensation programs, succession plans, the CEO's compensation and performance as well as acting as steward for the corporate pension plan. This committee met six times in 2006. Committee chair: Stanley J. Bright. Members: Timothy W. Faithfull, C. Kent Jespersen, Dr. Martha C. Piper, Luis Vázquez Senties and Donna Soble Kaufman (as an ex-officio member).

GORDON S. LACKENBAUER Director since September 2005 and resident of Calgary, Alta. Mr. Lackenbauer was Deputy Chairman of BMO Nesbitt Burns Inc. from 1990 to 2004. He is a director of Tembec Inc., NAL Oil & Gas Trust and CTV Globemedia Inc. Mr. Lackenbauer is also a Governor of Mount Royal College.

MARTHA C. PIPER Director since 2006 and resident of Vancouver, B.C. Dr. Piper was President and Vice-Chancellor of the University of British Columbia from 1997 to 2006. She is a Director of the Bank of Montreal, the B.C. Progress Board, the Pierre Elliot Trudeau Foundation and the Council of Canadian Academies.

STEPHEN G. SNYDER Director since 1996 and resident of Calgary, Alta. Mr. Snyder has been President and CEO of TransAlta Corporation since 1996. He is Chair of the Calgary Stampede Foundation and a director of the Calgary Exhibition and Stampede, the Canadian Imperial Bank of Commerce and the Alberta College of Art + Design. Mr. Snyder is a Trustee of the Conference Board of Canada.

LUIS VÁZQUEZ SENTIES Director since 2001 and resident of Mexico City, Mexico. He is President and CEO and Chair of Group Diavaz, an oilfield services and natural gas distribution company he founded with partners in 1973. Mr. Vázquez is Chair of Compania Mexicana de Gas, S.A. de C.V. and of the Mexican Natural Gas Association.

left to right Michael Kanovsky, Stephen Snyder, Bill Anderson

left to right Gordon Giffin, Luis Vázquez Senties, Donna Soble Kaufman, Martha Piper, Gordon Lackenbauer

left to right Kent Jespersen, Stanley Bright, Tim Faithfull

a wealth of experience

We have a highly qualified, independent Board whose members have diverse professional experience.

NOMINATING AND CORPORATE GOVERNANCE COMMITTEE

The committee is responsible for reviewing the composition and compensation of the Board of Directors and developing the company's approach to governance issues. This committee met four times in 2006. Committee chair: Ambassador Gordon D. Giffin. Members: C. Kent Jespersen, Michael M. Kanovsky, Gordon S. Lackenbauer and Donna Soble Kaufman (as an ex-officio member).

2006 CHANGES

Louis D. Hyndman retired from the Board in April 2006. Dr. Martha C. Piper joined the Board in July 2006.

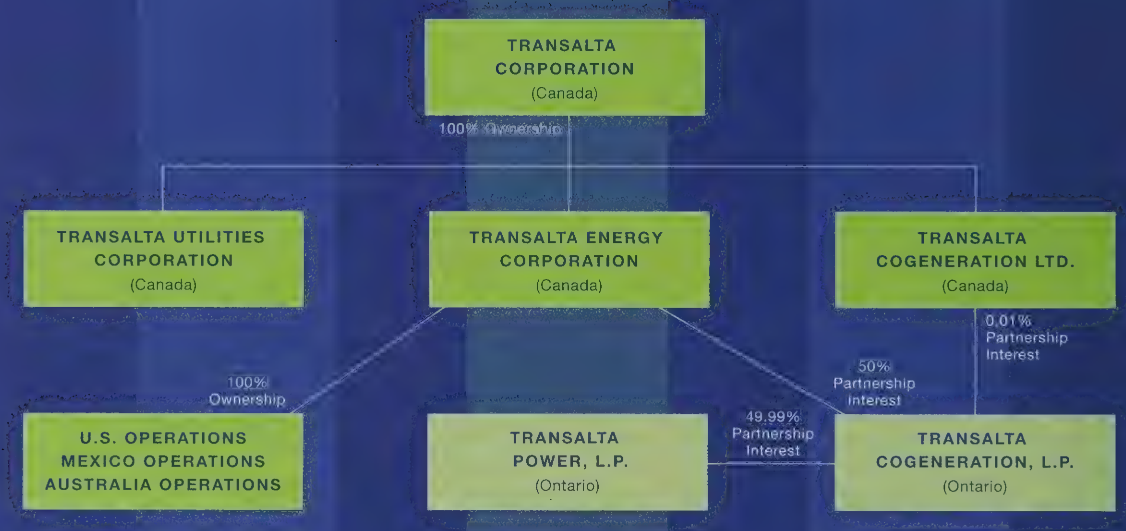
PLANT SUMMARY

Facility	Capacity (MW)	Ownership (%)	TransAlta operated	Capacity owned or operated (MW)	Fuel	Revenue source*	Contract expiry date
Genesee 3	450	50	No	225	Coal	Merchant	–
Keephills	766	100	Yes	766	Coal	Alberta PPA	2020
Keephills 3 [1]	450	50	Yes	225	Coal	Merchant	–
Sheerness	770	25	No	193	Coal	Alberta PPA	2020
Sundance [2]	2,073	100	Yes	2,073	Coal	Alberta PPA	2017, 2020
Wabamun [3]	279	100	Yes	279	Coal	Merchant	–
Fort Saskatchewan	118	30	Yes	35	Gas	Long-term contract	2019
Meridian	220	25	Yes	55	Gas	Long-term contract	2024
Poplar Creek	356	100	Yes	356	Gas	Long-term contract & Merchant	2024
Hydro assets [4]	801	100	Yes	801	Hydro	Alberta PPA	2013 – 2020
Castle River	46	100	Yes	46	Wind	Long-term contract	2011
McBride Lake	75	50	Yes	38	Wind	Long-term contract	2022
Summerview	68	100	Yes	68	Wind	Merchant	–
Western Canada Total	**6,472**			**5,160**			
Kent Hills [5]	75	100	Yes	75	Wind	Long-term contract	2033
Mississauga	108	50	Yes	54	Gas	Long-term contract	2017
Ottawa	68	50	Yes	34	Gas	Long-term contract	2012
Sarnia	575	100	Yes	575	Gas	Long-term contract & Merchant	2022
Windsor-Essex	68	50	Yes	34	Gas	Long-term contract & Merchant	2016
Eastern Canada Total	**894**			**772**			
Centralia	1,404	100	Yes	1,404	Coal	Merchant	–
Binghamton	47	100	Yes	47	Gas	Merchant	–
Centralia Gas	248	100	Yes	248	Gas	Merchant	–
Power Resources	200	50	No	100	Gas	Merchant	–
Saranac	240	37.5	No	90	Gas	Long-term contract	2009
Yuma	50	50	No	25	Gas	Long-term contract	2024
Imperial Valley [6] geothermal assets	327	50	No	163	Geothermal	Long-term contract & Merchant	2016 – 2035
Skookumchuck	1	100	Yes	1	Hydro	Merchant	–
Wailuku	10	50	Yes	5	Hydro	Long-term contract	2023
United States Total	**2,527**			**2,083**			
Campeche	252	100	Yes	252	Gas	Long-term contract	2028
Chihuahua	259	100	Yes	259	Gas	Long term contract	2028
Mexico Total	**511**			**511**			
Parkeston	110	50	Yes	55	Gas	Long-term contract	2016
Southern Cross [7]	245	100	Yes	245	Gas & Diesel	Long-term contract	2016
Australia Total	**355**			**300**			
Total	**10,759**			**8,826**			

1 *Facility under construction. Expected online 2011*
2 *Includes 53 MW uprate planned for 2007*
3 *To be retired by 2010*
4 *Comprised of 13 facilities*
5 *Construction to begin by the end of 2007. Expected online 2008*
6 *Comprised of 10 facilities*
7 *Comprised of nine facilities*
* *Merchant includes both short-term contracted and spot sales*

Details as of March 1, 2007


Results



This management's discussion and analysis (MD&A) should be read in conjunction with the consolidated financial statements included in this Annual Report and the fourth quarter news release dated Jan. 26, 2007. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles (GAAP). The effect of significant differences between Canadian and U.S. GAAP has been disclosed in *Note 30* to the consolidated financial statements. All tabular amounts in the following discussion are in millions of Canadian dollars unless otherwise noted. This MD&A is dated Feb. 27, 2007. Additional information respecting TransAlta Corporation ("TransAlta", "we", "our", "us" or the "corporation"), including its annual information form, is available on SEDAR at www.sedar.com and on our website at www.transalta.com.

> RESULTS OF OPERATIONS

The results of operations are presented on a consolidated basis and by business segment. TransAlta has two business segments: Generation and Corporate Development & Marketing (CD&M). TransAlta's segments are supported by a corporate group that provides finance, treasury, legal, environmental health and safety, sustainable development, corporate communications, government relations, information technology, human resources and other administrative support.

Some of TransAlta's accounting policies require management to make estimates or assumptions that in some cases may relate to matters that are inherently uncertain. Critical accounting policies and estimates include: revenue recognition, valuation and useful life of property, plant and equipment (PP&E), asset retirement obligations (ARO), valuation of goodwill, income taxes and employee future benefits. See additional discussion under Critical Accounting Policies and Estimates in this MD&A.

In this MD&A, the impact of foreign exchange fluctuations on foreign currency transactions and balances is discussed with the relevant income statement and balance sheet items. While individual balance sheet line items will be impacted by foreign exchange fluctuations, the net impact of the translation of individual items is reflected in the cumulative translation account on the consolidated balance sheet.

> HIGHLIGHTS AND SUMMARY OF RESULTS

During 2006, the corporation:

- Generated net earnings of $44.9 million compared to $186.3 million for 2005 and $169.2 million for 2004.
- Generated earnings on a comparable basis* of $233.8 million compared to $161.3 million for 2005 and $127.1 million for 2004.
- Generated cash flow from operations of $489.6 million compared to $619.8 million in 2005 and $591.2 million in 2004. In addition, contractually scheduled payments related to services provided in 2006 of approximately $185 million were received on Jan. 2, 2007.
- Invested $223.7 million in new and existing plants versus $325.9 million in 2005 and $345.7 million in 2004.
- Repaid $48.6 million of net debt compared to $262.9 million in 2005 and $367.4 million in 2004.

* *Earnings on a comparable basis is not defined under GAAP. Refer to the Non-GAAP Measures section on page 61 of this MD&A for a further discussion of earnings on a comparable basis, including a reconciliation to net earnings.*

The following table depicts key financial results and statistical operating data:

Year ended Dec. 31	**2006**	2005	2004
		(Restated, Note 1)	*(Restated, Note 1)*
Availability (%)	**89.0**	89.4	89.2
Production (GWh)	**48,213**	51,810	51,396
Revenue	**$ 2,796.5**	$ 2,838.5	$ 2,586.2
Gross margin [1]	**$ 1,491.4**	$ 1,442.0	$ 1,353.3
Operating income before mine closure and asset impairment charges [1]	**$ 478.5**	$ 456.8	$ 467.4
Mine closure charges	**(191.9)**	–	–
Asset impairment charges	**(130.0)**	(36.2)	–
Operating income [1]	**$ 156.6**	$ 420.6	$ 467.4
Earnings from continuing operations	**$ 44.9**	$ 174.3	$ 159.6
Earnings from discontinued operations, net of tax	**–**	12.0	9.6
Net earnings	**$ 44.9**	$ 186.3	$ 169.2
Basic and diluted earnings per common share:			
Earnings from continuing operations	**$ 0.22**	$ 0.88	$ 0.83
Earnings from discontinued operations, net of tax	**–**	0.06	0.05
Basic and diluted earnings per common share	**$ 0.22**	$ 0.94	$ 0.88
Total assets	**$ 7,460.1**	$ 7,693.1	$ 8,000.3
Total long-term financial liabilities	**$ 3,094.1**	$ 3,463.1	$ 3,601.5
Cash dividends declared per share	**$ 1.00**	$ 1.00	$ 1.00
Cash flow from operating activities	**$ 489.6**	$ 619.8	$ 591.2

1 *Gross margin, operating income before mine closure and asset impairment charges and operating income are not defined under Canadian GAAP. Refer to the Non-GAAP Measures section on page 61 of this MD&A for a further discussion of operating income and gross margin, including a reconciliation to net earnings.*

> STRATEGY AND KEY MEASURES

TransAlta is a wholesale power generator and marketer. We own, operate and manage a highly contracted and geographically diversified portfolio of assets and have expertise in generation fuels including coal, natural gas, hydro and renewable energy. Over the long term, two of our key financial goals are deliver greater than 10 per cent total shareholder return and a 10 per cent return on capital employed.

In addition to traditional metrics such as earnings per share, total shareholder return and return on capital employed, we have six sets of key measures which, in our opinion, are critical to meeting our goal. These key measures include a mix of operational, risk management and financial metrics against which we can measure and gauge our performance. Each are described below.

1. Availability and Production

Our plants must be available to meet the requirements of customers who have contracted our capacity or to be able to capture merchant market opportunities. Our long-term target is to have our plants available 90 per cent or more of the time.

Availability can be limited by the requirement to perform planned maintenance at regular intervals or by outages and derates caused by minor mechanical problems. While we expect that there will be a certain number of these unplanned outages or derates, our goal is to minimize these events through constant equipment monitoring and assessment, comprehensive maintenance plans and the formation of strategic relationships with suppliers. Over the past three years, we have achieved an average availability rate of 89.2 per cent, which is in line with our long-term target of 90 per cent availability.

Production is affected by our total generating capacity, the availability of our equipment and market conditions. During 2006, production decreased at our Centralia coal-fired plant (Centralia Coal) as well as at our hydro facilities. This decrease in production was partially offset by lower planned and unplanned outages at the Alberta Thermal plants (Alberta Thermal), incremental production from Genesee 3 and increased production at Centralia Gas and Poplar Creek.

Production increased in 2005, compared to 2004 due to the commissioning of Genesee 3 and from a full year of production at the Summerview wind farm. This increase in production was partially offset by the decommissioning of units one and two of the Wabamun plant in December 2004. Production was also negatively impacted by shutdowns caused by the Canadian National Railway (CN Rail) train derailment at Lake Wabamun and reduced production at our Poplar Creek plant.

2. Contracts

Our strategy is to contract a minimum of 75 per cent of our available output in any year to minimize our exposure to any potential volatility in electricity and gas prices in the markets in which we operate. This contracting strategy allows us to achieve a balance between cash flow stability and the ability to capture short-term opportunities in merchant markets.

Contracts can be structured as:

- capacity commitments, such as Alberta Power Purchase Arrangements (PPA), which allow TransAlta to minimize fuel cost risks by passing the majority of these costs on to the customer,
- a combination of production, availability and other services, such as at the Ontario and Alberta gas plants under which TransAlta is compensated for availability, electricity and steam production, or
- medium- to longer-term contracts directly with our customers, such as at Centralia Coal.

The remainder of our production is sold into markets as spot sales or under contracts with terms less than one year. During 2006, approximately 95 per cent of the Generation segment's revenues were derived from contracts with terms greater than one year. This percentage is consistent with prior years. A further discussion of these contracting strategies is provided beginning on page 38 of this MD&A.

3. Margin and Productivity

Together with increasing our production base, growing our gross margin is essential for our success. We manage margins through our contracting strategy and managing fuel costs. Coal-fired assets are mostly contracted through PPAs or long-term contracts. Fuel costs are managed by owning our own coal reserves or by signing contracts for stable and low cost supplies.

Gross margins at our contracted gas plants are generally managed by passing fuel costs on to customers or by signing long-term gas contracts that match the terms of the electricity and thermal sales. At our merchant gas plants, the margins are driven by the ratio of gas prices to electricity prices (market heat rates) and by our ability to produce electricity at heat rates that are better than the market heat rates.

In 2006, our gross margins increased due to incremental production from Genesee 3, favourable spark spreads and production at Poplar Creek, higher pricing and lower unplanned outages at Alberta Thermal, higher contract pricing and gains resulting from contracts recorded at fair market value (mark-to-market) at Centralia, increased gross margins at Sarnia and higher trading margins, partially offset by lower production at Centralia Coal, higher coal costs, Centralia Coal inventory writedown and lower hydro production.

During 2005, our margins increased due to higher gas prices which in turn influenced electricity prices. These higher electricity prices had a significant impact on the margins from our coal plants. Margins also increased from the addition of Genesee 3 and increased hydro production. These increases were partially offset by higher coal costs.

Gross margin per installed megawatt hour (MWh)[1] in 2006 increased from 2005 mainly due to favourable pricing at Alberta Thermal and Centralia Coal and from incremental revenue at Sarnia. In 2005, gross margin per installed MWh increased over 2004 due to increased hydro production and higher merchant coal capacity from the coal plants that benefited from higher electricity prices. These gains were partly offset by higher coal costs. Our operations, maintenance and administration (OM&A) costs reflect the operating cost of our facilities. These costs

1 We have traditionally presented gross margins and other key elements of the income statement on a per MWh produced. While for specific types of contracts this is an effective measure of profitability between periods, levels of production and associated revenues and costs are not comparable across all segments. To better gauge overall fleet performance and return on the investment in assets, we have presented overall results on an installed MWh, which is a measure of overall fleet capacity. We have used this measure for the first time in this annual report and will continue this practice going forward.

can fluctuate due to the timing and nature of planned maintenance activities. The remainder of OM&A costs reflect the cost of day-to-day operations. Our target is to absorb the impact of inflation in our recurring operating costs as much as possible through various productivity initiatives and measure our ability to do so based on the cost per installed MWh of capacity.

In 2006, our OM&A costs decreased $14.7 million due to lower planned outages and general cost reductions. On a per installed MWh basis, this cost was lower by $0.23 compared to the same period in 2005.

During 2005, our OM&A costs increased from $547.5 million to $596.0 million due to the addition of Genesee 3 and higher salary, contracting and material costs due to market demands for labour and commodities.

4. Capital Expenditures

We are in a long-cycle capital-intensive business. In 2006, we spent $123 million on routine and mine capital, $84 million on planned maintenance and $17 million on growth. In 2007, we expect to spend between $320 million and $340 million on sustaining expenditures which includes $100 – $110 million for routine capital, $80 million for mining equipment, $55 million for equipment modifications at Centralia Coal and $85 – $95 million on planned maintenance.

5. Cash Flow

Our goal in 2007 is to generate $650 – $750 million of cash flow from operating activities to meet the requirements of maintaining our equipment, reducing our debt, maintaining our dividend and having cash available to invest in growth initiatives.

In 2006, cash flow from operating activities decreased $130.2 million due to the timing of collection of receivables amounting to $185 million partially offset by higher cash earnings. These accounts receivable balances in respect of November 2006 revenues were contractually scheduled to be paid and were received on Jan. 2, 2007. These inflows will appear in our 2007 statements. In 2005, the November contractually scheduled payments were received on Dec. 30, 2005.

In 2005, cash flow from operating activities improved to $619.8 million from $591.2 million in 2004 due to improved cash earnings.

6. Financial Ratios

TransAlta is focused on maintaining a strong balance sheet and an investment grade credit rating. Financial strength provides us with continued access to capital and greater flexibility in contracting the output of our plants. Over the long term, our financial condition will dictate our ability to grow. Our objective is to maintain an investment grade rating to give us the capacity to take on new debt or issue equity.

At Dec. 31, 2006, our total debt (including non-recourse debt) to invested capital was 40.9 per cent (37.0 per cent excluding non-recourse debt) compared to the Dec. 31, 2005 ratio of 43.9 per cent and Dec. 31, 2004 ratio of 46.4 per cent. Cash flow to interest increased to 5.5x compared to 4.7x in 2005 and 4.3x in 2004. Cash flow to total debt increased to 26.2 per cent from 23.0 per cent in 2005 and 19.1 per cent in 2004.

> REPORTED EARNINGS

In 2006, reported earnings decreased to $44.9 million compared to $186.3 million in 2005 and $169.2 million in 2004 as shown below:

Net earnings for the year ended Dec. 31, 2004	$	169.2
Increased Generation gross margins		78.6
Higher CD&M gross margins		10.1
Increase in operations, maintenance and administration costs		(48.5)
Increase in depreciation expense		(10.4)
Increase in asset impairment charges		(36.2)
Decrease in net interest expense		18.8
Decrease in equity loss		7.6
Decrease in non-controlling interests		27.5
Decrease in income tax expense		7.0
Increase in earnings from discontinued operations, net of tax		2.4
Gain on sale of Meridian cogeneration facility (2004)		(17.7)
Gain on sale of TransAlta Power partnership units (2004)		(44.8)
Prior period regulatory decision (2004)		22.9
Other		(0.2)
Net earnings for the year ended Dec. 31, 2005	$	186.3
Increased Generation gross margins before writedown of coal inventory		85.0
Higher CD&M gross margins		8.8
Decrease in operations, maintenance and administration costs		14.7
Increase in depreciation expense		(42.4)
Writedown of coal inventory to lower of cost and market (2006)		(44.4)
Centralia mine closure charges (2006)		(191.9)
Increase in asset impairment charges		(93.8)
Decrease in net interest expense		20.1
Increase in equity loss		(16.1)
Increase in non-controlling interests		(33.0)
Decrease in income tax expense		165.4
Earnings from discontinued operations, net of tax (2005)		(12.0)
Other		(1.8)
Net earnings for the year ended Dec. 31, 2006	**$**	**44.9**

In 2006, our gross margins before the Centralia Coal inventory writedown were $93.8 million higher than in 2005 due to incremental production from Genesee 3, favourable spark spreads and production at Poplar Creek, higher pricing and lower unplanned outages at Alberta Thermal, higher contract pricing and mark-to-market gains at Centralia, increased gross margins at Sarnia and higher trading margins. These increases were partially offset by higher unplanned outages and derates at Centralia Coal, higher coal costs and lower hydro production.

For the year ended Dec. 31, 2005, our gross margins were $88.7 million higher than in 2004 due to the addition of Genesee 3, higher hydro production, higher prices at Centralia Coal and Alberta Thermal, higher contract prices at some of our gas plants and higher trading margins. These increases were offset by increased coal costs, increased net penalties at Alberta Thermal as a result of our planned maintenance activities and the decommissioning of units one and two of the Wabamun plant.

In 2006, OM&A costs decreased $14.7 million from 2005 due to lower planned maintenance and general cost reductions. OM&A costs increased $48.5 million in 2005 compared to the same period in 2004 due to the addition of Genesee 3, materials cost escalations, increased incentive compensation costs and increased labour costs. These increases were partially offset by lower planned maintenance expenses.

In 2006, depreciation and amortization increased $42.4 million due to the impairment of turbines held in inventory, revised depreciation rates at the Ottawa, Mississauga, Windsor-Essex, Fort Saskatchewan and Meridian plants, and the impact of revised ARO estimates at Alberta Thermal. Depreciation and amortization increased by $10.4 million in 2005 compared to the same period in 2004 primarily due to the addition of Genesee 3.

Interest expense decreased $20.1 million compared to 2005 due to lower debt levels, unwinding of cross currency swaps, favourable foreign exchange rates and the settlement of net investment hedges, partially offset by higher floating interest rates. Interest expense declined in 2005 by $18.8 million compared to 2004 due to reduced debt levels.

In 2006, non-controlling interests increased $33.0 million compared to 2005 due to the impairment charge attributable to TransAlta Power, L.P.'s (TA Power) interest in the Ottawa plant in 2005 as discussed in Significant Events in this MD&A. Excluding this impairment charge, non-controlling interests decreased $3.2 million.

Non-controlling interests decreased by $27.5 million in 2005 as a result of the impairment of the Ottawa facility. Excluding this amount, non-controlling interests increased $8.7 million in 2005 compared to 2004 as we disposed of our remaining interest in TA Power in 2004.

As a result of the decision to stop mining at the Centralia Coal mine, we wrote down the remaining internally produced coal inventory held at Centralia to fair market value and recognized various closure-related charges that are discussed in more detail in the Significant Events section of this MD&A.

During the fourth quarter of 2006, we recorded an impairment charge for the Centralia Gas plant as the full book value of this plant was unlikely to be recovered from future cash flows. In 2005, the value of the Ottawa plant in TransAlta Cogeneration, L.P. (TA Cogen) was written down to its fair value. The charge for the Ottawa impairment in 2005 was offset by a reduction in earnings attributable to non-controlling interests.

> SIGNIFICANT EVENTS

Our consolidated financial results include the following significant events.

2006

Centralia Coal Mine

On Nov. 27, 2006, we stopped mining at our Centralia Coal mine as a result of increased costs and unfavourable geological conditions. Inventory extracted up to the date on which we ceased operations will be consumed throughout 2007. Coal requirements for the foreseeable future are expected to be sourced from coal imported from the Powder River Basin (PRB). In 2007, we will reduce production at the plant by 2,500 gigawatt hours (GWh) until the necessary equipment modifications can be made to burn the higher thermal content PRB coal. The modifications to the equipment at Centralia Coal are anticipated to be completed after the 2008 maintenance turnaround currently scheduled for the second quarter of 2008.

We incurred an after-tax charge of $153.6 million ($0.76 per share) due to asset and inventory writedowns, reclamation liabilities, severance costs and other charges.

As required by GAAP, the restructuring charges appear on their appropriate lines on the statements of earnings but have been summarized in the following table and are described below:

Writedown of coal inventory	$ 44.4
Impact on gross margin	(44.4)
Mine closure charges	
Mine equipment and infrastructure writedown	72.1
ARO writedown	81.3
Severance costs and other	38.5
Total mine closure charges	191.9
Loss before income taxes	$ (236.3)
Income tax recovery	82.7
Net loss impact of event	$ (153.6)

Writedown of coal inventory

Since all coal requirements are now being sourced from an external source, the existing internally produced coal inventory was written down to fair market value, which is the current PRB cost.

Mine equipment and infrastructure writedown

Mine equipment used in the mine was valued at the lower of current net book value and fair value. The majority of this equipment is anticipated to be sold in 2007. Mining infrastructure, which includes processing facilities, was also written down to its expected fair values.

ARO writedown

The unamortized cost of future reclamation expenses was recognized immediately.

Severance costs and other

This includes salaries payable to employees, estimated benefit obligations, other transition payments as a result of the closure, amounts accrued for estimated contract termination penalties, writedown of materials and supplies and other immaterial amounts.

Further, since Centralia Coal will not be operating at full capacity in 2007 and 2008, certain contracts are no longer backed by physical production of the plant and therefore no longer qualify for hedge accounting. Therefore, under GAAP, we recognized mark-to-market gains on these contracts. As well, we have entered into additional contracts to offset some of this exposure recorded at fair market value. As a result, on a net basis, based on current forward price estimates, we have recorded mark-to-market gains of $35.5 million in 2006. These mark-to-market adjustments, which are not included in the table above, have no cash impact on the 2006 financial statements but the fair market value will continue to change as market prices change until settlement occurs in future periods.

Centralia Gas Impairment

During our annual impairment review, we concluded that the full book value of our Centralia Gas facility was unlikely to be recovered from future cash flows due to changes in TransAlta's outlook for the plant's profitability based on market dispatch rates and trading values. As a result, we recorded an $84.4 million after-tax ($0.42 per share) impairment charge to write the plant down to fair value.

Notice of Preferred Securities Redemption

On Nov. 22, 2006, we announced our intention to redeem all of our 7.75 per cent Preferred Securities which had an aggregate principal of $175.0 million. We redeemed these securities on Jan. 2, 2007.

Designation of Eligible Dividends

Under the legislation proposed by the Department of Finance, Canadian residents are entitled to a higher gross-up and dividend tax credit in 2006 and subsequent years if they receive eligible dividends. The dividends paid by us during 2006 are eligible dividends as defined in the draft legislation. Dividends expected to be paid in 2007 are also expected to be eligible.

Amendment to Dividend Reinvestment and Share Purchase (DRASP) Plan

On Oct. 20, 2006, we announced that effective Jan. 1, 2007, the corporation will amend the DRASP plan. As a result, after Dec. 31, 2006, the five per cent discount on the price of shares purchased through the DRASP plan and issued from treasury will be suspended. After Dec. 31, 2006, shares purchased under the DRASP plan will be acquired in the open market at 100 per cent of the average purchase price of common shares acquired on the Toronto Stock Exchange on the investment dates. Shares issuable under the DRASP plan have not been registered under any U.S. Federal or State Securities laws and U.S. persons or residents are not eligible to participate in the DRASP plan.

Wabamun Outage

In 2005, an oil spill at Lake Wabamun, Alberta forced us to shut down unit four of our Wabamun coal-fired plant for 39 days. In the fourth quarter of 2006, we settled a portion of our outstanding claim for lost margin and incremental expenses. The terms of the settlement are subject to a confidentiality agreement. The settlement is included in merchant revenues.

Sarnia Power Plant

On Feb. 15, 2006, we signed a five-year contract with the Ontario Power Authority (OPA) for our Sarnia Regional Cogeneration Power Plant to supply an average of 400 megawatt (MW) of electricity to the Ontario electricity market. The contract was effective Jan. 1, 2006.

Centralia Coal Reduced Production and Economic Dispatch

Due to heavy rainfall in the Pacific Northwest in the first quarter of 2006, we derated Centralia Coal and started rebuilding our coal inventory. The impact of derating the plant during this time was partially offset by increasing coal imports and purchasing replacement power. We experienced 875 GWh of lower production during the first quarter of 2006 compared to the same period of 2005.

During the second quarter of 2006, lower market prices allowed us to purchase power at a price lower than our variable cost of production. As a result, Centralia Coal did not operate for the majority of the second quarter. We experienced 1,936 GWh of lower production during the second quarter compared to the same period of 2005.

In the third quarter of 2006, the 702 MW unit 2 experienced a turbine blade failure. As a result of the event, total production was reduced by 727 GWh. Also in the third quarter of 2006, higher unplanned outages resulted in 232 GWh of lower production.

In the fourth quarter of 2006, 358 GWh of production at Centralia Coal was lost as a result of PRB coal test burns at the plant.

For the year ended Dec. 31, 2006, as a result of the above-mentioned events, total production at Centralia was 4,128 GWh lower than in 2005.

Purchase of Wailuku River Hydroelectric L.P.

On Feb. 17, 2006, we purchased a 50 per cent interest in Wailuku River Hydroelectric L.P. through Wailuku Holding Company, LLC (Wailuku) for cash of US$1.0 million (Cdn$1.2 million). Wailuku had debt of US$19.2 million (Cdn$22.3 million) at the time of acquisition. Refer to *Note 20* of the consolidated financial statements for the year ended Dec. 31, 2006 for the purchase price allocation. Wailuku owns a run-of-river hydro facility with an operating capacity of 10 MW. MidAmerican Energy Holdings Company (MidAmerican) owns the other 50 per cent interest in Wailuku.

Change in Depreciation Rate

In the first quarter of 2006, we changed the depreciation method of the Windsor-Essex, Mississauga, Ottawa, Meridian and Fort Saskatchewan plants. Previously, these plants were amortized on a unit of production method over the life of the plants. After reviewing the estimated useful life and considering the uncertainty for the plants' operations beyond the terms of the current sales contracts, we determined that it was more reasonable to allocate the remaining net book value of the plants on a straight-line basis over the remaining term of the respective contracts. This increase in depreciation is offset by a reduction in earnings attributable to the non-controlling interests in our consolidated statement of earnings.

Keephills 3 Project

On March 14, 2006, we signed a development agreement with EPCOR Utilities Inc. (EPCOR) to jointly examine the development of the Keephills 3 power project, a proposed 450 MW supercritical coal-fired plant adjacent to our existing Keephills facility.

2006 Federal and Alberta Budgets

On May 24, 2006, the Alberta budget received Royal Assent. As a result, the general corporate income tax rate for Alberta was reduced from 11.5 per cent to 10 per cent effective April 1, 2006. The federal budget received Royal Assent on June 22, 2006. As a result, the general corporate federal tax rate will be reduced from 21 per cent to 19 per cent by Jan. 1, 2010. The corporate surtax has been eliminated for taxation years ended after Dec. 31, 2007 and the federal capital tax has been eliminated effective Jan. 1, 2006. The carry-forward period for non-capital losses and investment tax credits earned after 2005 has been extended from 10 to 20 years. As a result of these changes, in the second quarter the corporation reduced income tax expense by $55.3 million, which reflected the impact of these changes on prior years' earnings.

2005

Commissioning of Genesee 3

On March 1, 2005, we, jointly with EPCOR, commissioned the third unit of the Genesee coal-fired facility. We own a 50 per cent interest in this unit.

Wabamun Outage

On Aug. 3, 2005, a CN Rail train derailment resulted in an oil spill in Lake Wabamun, Alberta. We were forced to shut down unit four of our Wabamun coal plant as a result. The facility was restored to full operations on Sept. 11, 2005.

Impairment of the Ottawa Facility

In the fourth quarter of 2005, after completing our impairment reviews, we concluded that the carrying value of the Ottawa cogeneration facility exceeded its fair value in the accounts of TA Cogen, a subsidiary of TransAlta Corporation. Consequently, TA Cogen recorded an impairment provision of $78.3 million in the fourth quarter of 2005. In the accounts of the corporation, however, the carrying value of the Ottawa facility is lower than that of TA Cogen. TA Cogen purchased this facility from the corporation at a price that was higher than the cost the corporation paid to construct it. We recognized a $36.2 million charge to reflect the difference in carrying values between the accounts of the corporation and those of TA Cogen. This charge was offset by a reduction in the earnings attributable to the non-controlling interests in our consolidated statement of earnings. The net result is that the impairment of the plant in the accounts of TA Cogen had no impact on the net earnings of the corporation.

2004

Decommissioning of Wabamun Plant

In the fourth quarter of 2002, we implemented a phased decommissioning of the Wabamun facility by removing the 139 MW unit three from service in 2002 and decommissioning units one and two (62 MW and 57 MW, respectively) on Dec. 31, 2004. We plan to retire unit four (279 MW) in 2010 when its operating license expires. The PPA for the plant expired on Dec. 31, 2003 and all production is therefore sold on the spot market.

Sale of Meridian Cogeneration Facility

On Dec. 1, 2004, we completed the sale of our 50 per cent interest in the 220 MW Meridian cogeneration facility located in Lloydminster, Saskatchewan, to TA Cogen for its fair value of $110.0 million. TA Cogen financed the acquisition through the use of $50.0 million of cash on hand, by issuance of $30.0 million of units to each of TA Power and TransAlta Energy Corporation (TEC) and the issue of an advance to TEC for $30.0 million. We recorded a pre-tax gain of $17.7 million (after-tax gain of $11.5 million) or $0.06 per common share.

Sale of TA Power Units

For the year ended Dec. 31, 2004, we recognized $44.8 million of dilution gains on the exercise of warrants and subsequent sale of units.

On Dec. 3, 2004, we sold our remaining 7.1 million units of TA Power at $9.00 each for net proceeds of $64.0 million, resulting in a pre-tax gain of $20.6 million (after-tax gain of $13.4 million) and including a dilution gain of $11.6 million. We purchased these units in connection with our sale of the Sheerness Generating Station to TA Cogen in 2003.

Summerview Wind Farm

In the third quarter of 2004, we commissioned the 68 MW Summerview wind farm.

Prior Period Regulatory Decision

In response to a complaint filed by San Diego Gas & Electric Company under Section 206 of the *Federal Power Act* (FPA), the Federal Energy Regulatory Commission (FERC) established a claim of approximately US$46 million in refunds owing by TransAlta for sales made by it in the organized markets of the California Power Exchange (PX) and the California Independent System Operator (ISO) during the Oct. 2, 2000 through June 20, 2001 period (the Main Refund Transactions). TransAlta has provided US$46 million to account for refund liabilities relating to Main Refund Transactions.

TransAlta filed a cost of service based petition for relief from these refund obligations. FERC rejected TransAlta's relief petition. On Dec. 1, 2006 TransAlta filed for a rehearing of FERC's rejection. FERC has not yet issued a decision on rehearing.

During settlement negotiations, the complaintants have sought to obtain refunds for two sets of transactions beyond the Main Refund Transactions. The first set includes sales made by sellers in the PX and ISO markets in the period May 1 to Oct. 1, 2001 (The Summer Transactions). The other set includes bilateral transactions between all sellers and a component of the California Department of Water Resources (CDWR) referred to as CERS (The CERS Transactions). FERC has specifically rejected attempts to introduce refunds for the Summer and CERS Transactions. Nonetheless, the California parties have sought rehearing of FERC's refusal and appealed the refusal to the U.S. Court of Appeals for the Ninth Circuit. TransAlta does not presently believe the California parties will be successful in obtaining refunds alleged for the Summer and CERS transactions. TransAlta has not made any provision for such alleged refunds at this time.

> SUBSEQUENT EVENTS

Keephills 3 Power Plant

On Feb. 14, 2007, the Alberta Energy and Utilities Board approved the development of the 450 MW Keephills 3 coal-fired power plant. The plant will be developed jointly by EPCOR and TransAlta. On Feb. 26, 2007, TransAlta and EPCOR announced that we will proceed with building the Keephills 3 project. The capital cost of the project is expected to be approximately $1.6 billion.

Power Purchase Agreement with New Brunswick Power

On Jan. 19, 2007, we announced a 25-year long-term contract with New Brunswick Power Distribution and Customer Service Corporation to provide 75 MW of wind power. We will construct, own and operate a wind power facility in New Brunswick with an estimated capital cost of $130 million. Natural Forces Technologies Inc. is our co-developer on this project and commercial operations are expected to begin by the end of 2008.

> SEGMENTED BUSINESS RESULTS

Generation Owns and operates hydro, wind, geothermal, gas- and coal-fired plants and related mining operations in Canada, the United States and Australia. At Dec. 31, 2006, Generation had 8,366 MW of gross generating capacity in operation (7,962 MW net ownership interest) and 353 MW net under construction.

We have strategic alliances with EPCOR, ENMAX Corporation (ENMAX) and MidAmerican. The EPCOR alliance provided the opportunity for us to acquire a 50 per cent ownership in the 450 MW Genesee 3 project and for the current development underway for the Keephills 3 project. ENMAX and TransAlta each own 50 per cent of the partnership in the McBride Lake wind project. MidAmerican owns the other 50 per cent interest in CE Generation LLC (CE Gen) and Wailuku.

Our results are seasonal due to the nature of the electricity market and related fuel costs. Higher maintenance costs are ordinarily incurred in the second and third quarters when electricity prices are expected to be lower as electricity prices generally increase in the winter months in the Canadian market. Margins are also typically impacted in the second quarter due to the volume of hydro production resulting from spring runoff and rainfall in the Canadian and U.S. markets.

The results of the Generation segment were as follows:

Year ended Dec. 31	2006 Total	2006 Per MWh produced	2005 (Restated, Note 1) Total	2005 (Restated, Note 1) Per MWh produced	2004 (Restated, Note 1) Total	2004 (Restated, Note 1) Per MWh produced
Revenues	**$ 2,611.9**	**$ 54.17**	$ 2,607.5	$ 50.33	$ 2,341.7	$ 45.56
Fuel and purchased power	**(1,186.2)**	**(24.60)**	(1,222.4)	(23.59)	(1,035.2)	(20.14)
Gross margin	**1,425.7**	**29.57**	1,385.1	26.73	1,306.5	25.42
Operations, maintenance and administration	**458.3**	**9.51**	481.1	9.29	450.0	8.76
Depreciation and amortization	**396.9**	**8.23**	354.9	6.85	343.5	6.68
Taxes, other than income taxes	**21.1**	**0.44**	21.3	0.41	20.5	0.40
Intersegment cost allocation	**27.8**	**0.58**	26.0	0.50	26.0	0.51
Operating expenses	**904.1**	**18.75**	883.3	17.05	840.0	16.34
Mine closure charges	**191.9**	**3.98**	–	–	–	–
Asset impairment charges	**130.0**	**2.70**	36.2	0.70	–	–
Gain on sale of Meridian cogeneration facility	**–**	**–**	–	–	17.7	0.34
Gain on sale of TransAlta Power partnership units	**–**	**–**	–	–	44.8	0.87
Operating income	**$ 199.7**	**$ 4.14**	$ 465.6	$ 8.99	$ 529.0	$ 10.29
Production (GWh)	**48,213**		51,810		51,396	
Availability (%)	**89.0**		89.4		89.2	

For the year ended Dec. 31, 2006, our availability was marginally lower at 89.0 per cent compared to 89.4 per cent in 2005 and 89.2 per cent recorded in 2004. In 2006, we experienced higher unplanned outages and derates at Centralia Coal, which were mostly offset by lower planned outages at Poplar Creek, Alberta Thermal and Genesee 3 combined with lower planned and unplanned outages at Sarnia compared to 2005.

Generation's revenues are derived from the production of electricity and steam as well as ancillary services such as system support. In 2006, gas- and coal-fired facilities had exposure to market fluctuations in energy commodity prices representing six per cent and 23 per cent of our total generating capacity, respectively. We closely monitor the risks associated with these commodity price changes on our future operations and, where appropriate, use various physical and financial instruments to hedge our assets and operations from such price risk. These contracts are designated as effective hedge positions of future cash flows or fair values of the output and production of our owned assets. Under Canadian GAAP, settlement accounting is used for transactions that qualify for hedge accounting. Under U.S. GAAP, hedging activities are accounted for in accordance with Financial Accounting Standards Board (FASB) Statement 133.

For the year ended Dec. 31, 2006, 95 per cent of our total production was subject to contracted prices (2005 – 91 per cent; 2004 – 89 per cent), with the remaining production subject to market pricing. Revenues received under contractual arrangements are not subject to short-term fluctuations in the spot price for electricity.

Generation segment revenues are generated from the following revenue streams:

Alberta PPAs are arrangements under which we earn monthly capacity revenues, which are designed to recover fixed costs and provide a return on capital for our plants and mines. We also earn energy payments for the recovery of predetermined variable costs of producing energy, an incentive/penalty for achieving above/below the targeted availability and an excess energy payment for power production above committed capacity. Our Sundance, Keephills, Sheerness and contracted portion of the Alberta hydro assets are included in this segment.

Long-term contracts are similar to PPAs. We define a long-term contract as having an original term between 10 and 25 years. Long-term contracts are typically for gas-fired cogeneration plants and have between one and four customers per plant. Revenues are derived from payments for capacity and/or the production of electrical energy and steam. The results from our Mississauga, Windsor-Essex, Wailuku, Ottawa, Fort Saskatchewan and Meridian plants as well as the contracted portions of Sarnia, Poplar Creek and TransAlta Wind, are included in this category.

Merchant revenue is derived from the sale of production only, with multiple customers per plant. Production is sold via: medium-term contract sales (typically two to 10 years), short-term asset-backed trading, and spot or short-term (less than one year) forward markets. The results from Centralia Coal, Centralia Gas, Genesee 3, Wabamun and Binghamton; excess energy sales from Sundance, Keephills, Hydro, Sheerness; and the uncontracted portions of TransAlta Wind, Poplar Creek and Sarnia are included in this category.

CE Gen earns revenues from 10 geothermal plants and three gas-fired facilities. Eight of the geothermal plants sell their output under long-term contracts expiring between 2016 and 2035. One facility is partially contracted while the remaining facility sells its output on the spot market but has an option to sell output under a 35-year contract based on market prices. The gas-fired facilities sell their output under fixed-price contracts ranging from three to 18 years of remaining contract life, with expiration dates of 2009 and 2024. All three facilities have gas supply arrangements in place for the duration of the electricity sales contracts.

Our production volumes, electricity and steam production revenues and fuel and purchased power costs from these four sources are presented below:

Year ended Dec. 31, 2006	**Production (GWh)**	**Revenue**	**Fuel & purchased power**	**Gross margin**	**Revenue per MWh**	**Fuel & purchased power per MWh**	**Gross margin per MWh**
Alberta PPAs	**25,343**	**$ 736.8**	**$ 228.0**	**$ 508.8**	**$ 29.07**	**$ 9.00**	**$ 20.07**
Long-term contracts	**6,908**	**635.4**	**357.8**	**277.6**	**91.98**	**51.80**	**40.18**
Merchant	**13,140**	**964.3**	**535.7**	**428.6**	**73.39**	**40.77**	**32.62**
CE Gen	**2,822**	**275.4**	**64.7**	**210.7**	**97.59**	**22.93**	**74.66**
	48,213	**$ 2,611.9**	**$ 1,186.2**	**$ 1,425.7**	**$ 54.17**	**$ 24.60**	**$ 29.57**

Year ended Dec. 31, 2005 *(Restated, Note 1)*	Production (GWh)	Revenue	Fuel & purchased power	Gross margin	Revenue per MWh	Fuel & purchased power per MWh	Gross margin per MWh
Alberta PPAs	25,279	$ 682.1	$ 202.8	$ 479.3	$ 26.98	$ 8.02	$ 18.96
Long-term contracts	6,947	647.9	392.7	255.2	93.26	56.53	36.73
Merchant	16,630	983.2	554.6	428.6	59.12	33.35	25.77
CE Gen	2,954	294.3	72.3	222.0	99.63	24.48	75.15
	51,810	$ 2,607.5	$ 1,222.4	$ 1,385.1	$ 50.33	$ 23.59	$ 26.74

Year ended Dec. 31, 2004 *(Restated, Note 1)*	Production (GWh)	Revenue	Fuel & purchased power	Gross margin	Revenue per MWh	Fuel & purchased power per MWh	Gross margin per MWh
Alberta PPAs	25,836	$ 679.2	$ 187.3	$ 491.9	$ 26.29	$ 7.25	$ 19.04
Long-term contracts	7,183	581.9	341.9	240.0	81.01	47.60	33.41
Merchant	15,676	799.5	439.3	360.2	51.00	28.02	22.98
CE Gen	2,701	281.1	66.7	214.4	104.07	24.69	79.38
	51,396	$ 2,341.7	$ 1,035.2	$ 1,306.5	$ 45.56	$ 20.14	$ 25.42

Alberta PPAs

In 2006, production of 25,343 GWh from our PPA facilities was 64 GWh higher than 2005 due to lower planned and unplanned outages at Alberta Thermal, partially offset by lower customer demand.

Production in 2005 of 25,279 GWh from our PPA facilities was 557 GWh lower than 2004 primarily due to higher planned outages.

For 2006, revenues were $54.7 million ($2.09 per MWh) higher than in 2005 due to lower planned and unplanned outages and higher net prices.

Revenues for 2005 were essentially flat compared to 2004 as the impact of higher prices was offset by the net penalties paid during both planned and unplanned outages.

For the year ended Dec. 31, 2006, fuel costs increased $25.2 million ($0.98 per MWh) over 2005 due to an increase in coal costs as a result of higher overburden removal and increased input costs.

For the year ended Dec. 31, 2005, fuel costs increased $15.5 million ($0.77 per MWh) over 2004 due to increased coal costs as a result of higher overburden removal and increased input costs.

Long-Term Contracts

In 2006, long-term contract volumes decreased 39 GWh from 2005 due to lower production at Ottawa primarily due to our decision to sell gas from that facility rather than produce electricity, partially offset by increased production at other gas facilities.

Long-term contract volumes declined 236 GWh to 6,947 GWh in 2005 from 2004 due to higher planned outages and reduced customer demand at certain gas-fired facilities.

Revenues declined $12.5 million ($1.28 per MWh) in 2006 compared to 2005 due to the impact of lower natural gas prices on revenues charged to customers, partially offset by incremental revenues from gas sales at Ottawa.

In 2005, our revenue increased $66.0 million ($12.25 per MWh) from 2004 due to the impact of higher natural gas prices on revenues charged to customers, increased thermal volumes at Sarnia and revised contract pricing at other gas plants.

Fuel and purchased power costs decreased by $34.9 million ($4.73 per MWh) for the year ended Dec. 31, 2006 compared to the same period in 2005 due to lower natural gas prices partially offset by incremental gas purchases at Ottawa.

For the year ended Dec. 31, 2005, fuel and purchased power costs increased $50.8 million ($8.93 per MWh) compared to 2004 primarily due to higher natural gas prices.

Merchant Production

In 2006, spot electricity prices were higher in Alberta, but lower in the Pacific Northwest and Ontario. Gas prices decreased in all three markets resulting in higher spark spreads in Alberta while spark spreads decreased in Ontario and the Pacific Northwest.

	Alberta		Mid-C		Ontario	
	Electricity price	Spark spreads	Electricity price	Spark spreads	Electricity price	Spark spreads
2006	**$ 80.58**	**$ 34.95**	**$ 45.40**	**$ 3.31**	**$ 46.41**	**$ (7.93)**
2005	70.01	8.91	58.52	6.82	68.40	(5.23)
2004	54.59	8.71	42.34	6.31	49.96	(5.39)

In 2006, merchant production decreased 3,490 GWh to 13,140 GWh due to reduced production at Centralia Coal and lower hydro production, offset by increased production from Genesee 3, Centralia Gas and Poplar Creek.

In 2005, merchant production increased 954 GWh to 16,630 GWh due to the commissioning of Genesee 3, increased hydro production, and lower planned outages at Alberta Thermal. These increases were partially offset by the lost production at Alberta Thermal due to the CN Rail train derailment, the decommissioning of units one and two of our Wabamun plant and reduced production at Poplar Creek.

For the year ended Dec. 31, 2006, gross margins were flat (increase of $6.85 per MWh) compared to 2005. Gross margin on a per MWh basis was higher in 2006 due to lower production, as mentioned above.

At Centralia Coal, margins decreased as a result of higher coal costs, writedown of coal inventory, higher unplanned outages and derates, and the strengthening of the Canadian dollar, partially offset by higher contract pricing, unrealized mark-to-market gains on contracts that no longer qualify for hedge accounting and benefits due to economic dispatch.

Merchant margins also decreased due to lower hydro production, partially offset by incremental revenue from Sarnia, favourable spark spreads and higher production at Poplar Creek, and favourable production at Genesee 3.

Merchant gross margins in 2005 increased $68.4 million ($2.79 per MWh) from 2004 due to the addition of Genesee 3, reduced planned outages at Alberta Thermal and increased production and pricing at Centralia Coal and Hydro. These increases were offset by higher fuel costs at Centralia Coal, lost margin due to the CN Rail train derailment at Wabamun, and the decommissioning of units one and two of the Wabamun plant.

CE Gen

During 2006, production from CE Gen decreased 132 GWh to 2,822 GWh from 2005 due to higher planned outages at the Imperial Valley, Power Resources and Yuma plants.

During 2005, production from CE Gen increased by 253 GWh to 2,954 GWh primarily due to increased production at the Imperial Valley and Saranac facilities due to lower planned outages.

For the year ended Dec. 31, 2006, gross margin decreased $11.3 million ($0.49 per MWh) compared to the same period in 2005 primarily due to reduced production and the strengthening of the Canadian dollar, partially offset by increased pricing at the gas-fired facilities.

In 2005, gross margins increased $7.6 million ($4.23 per MWh) from 2004 due to higher volumes partially offset by higher gas prices and the strengthening of the Canadian dollar.

OM&A Expense

In 2006, our OM&A expenses decreased $22.8 million ($0.22 per MWh increase) from 2005 due to lower planned outages and general cost reductions.

Our OM&A costs increased $31.1 million ($0.53 per MWh) in 2005 to $481.1 million ($9.29 per MWh) from 2004 due to the addition of Genesee 3, increased incentive compensation costs and cost escalations related to materials.

Planned Maintenance

The table below shows the amount of planned maintenance capitalized and expensed, excluding CE Gen:

Year ended Dec. 31	**2006**	2005	2004
Capitalized	**$ 84.2**	$ 119.1	$ 88.1
Expensed	**55.4**	68.3	73.0
	$ 139.6	$ 187.4	$ 161.1
GWh lost	**2,325**	2,818	2,507

Production lost in the year ended Dec. 31, 2006 decreased by 493 GWh from 2005 due to reduced planned outages across the fleet. In 2005, production lost increased 311 GWh compared to 2004 due to the completion of four planned maintenance events at our gas units in the year.

During the year ended Dec. 31, 2006, capitalized and expensed maintenance costs were lower compared to 2005 due to the benefits from multi-year maintenance plans. The increase in capitalized maintenance of $31.0 million in 2005 from 2004 relates to the completion of four planned maintenance events at our gas units during that year.

Annually, we purchase long-lead materials for future years' outages as lead times on these items can extend well beyond one year. In 2006, we spent $5.3 million on such items compared to $6.2 million in 2005 and $19.8 million in 2004. These items are not included in the chart on the previous page.

Depreciation and Amortization

Depreciation and amortization increased $42.0 million in 2006 ($1.38 per MWh) compared to 2005 primarily due to the change in depreciation rates at the Windsor-Essex, Mississauga, Ottawa, Meridian and Fort Saskatchewan plants, revised ARO estimates at Alberta Thermal and the impairment recorded on turbines held in inventory. The change in depreciation rates at the above-mentioned plants resulted in an increase in depreciation expense that was offset by a decrease in non-controlling interests.

Depreciation and amortization increased by $11.4 million in 2005 due to the addition of Genesee 3 and equipment retired during planned outages.

Taxes Other than Income Taxes

In 2006, taxes other than income taxes were consistent with both 2005 and 2004.

Intersegment Cost Allocations

In 2006, intersegment cost allocations were consistent with both 2005 and 2004.

Corporate Development & Marketing Derives revenue and earnings from the wholesale trading of electricity and other energy-related commodities and derivatives not supported by TransAlta-owned generation assets. CD&M also utilizes contracts of various durations for the forward sales of electricity and purchases of natural gas, coal and transmission capacity to effectively manage available generating capacity and fuel and transmission needs on behalf of Generation. These results are included in the Generation segment. Key performance indicators for CD&M's proprietary trading include margins and value at risk.

CD&M acts to maximize margins from the production and sale of electricity, minimize the cost of natural gas used to generate electricity and steam, and to reduce the risk to the corporation from unplanned outages by acquiring replacement power at the lowest possible price.

CD&M uses commodity derivatives to manage risk, earn trading revenue and gain market information. The portfolio of derivatives consists of physical and financial instruments including forwards, swaps, futures and options in various commodities. These contracts meet the definition of trading activities and have been accounted for using fair values for both Canadian and U.S. GAAP. Changes in the fair values of the portfolio are recognized in income in the period they occur.

In compliance with FASB Emerging Issues Task Force (EITF) 03-11, *Reporting Realized Gains and Losses on Derivative Instruments that are Subject to FASB Statement 133, Accounting for Derivative Instruments and Hedging Activities, and Not Held for Trading Purposes as Defined in Issue No. 02-3,* we have concluded that CD&M contracts settled in the real-time physical markets meet the definition of derivative contracts held for delivery and therefore revenues from these contracts are reported on a gross basis (trading revenues and trading purchases are shown separately) in the consolidated statement of earnings.

The results of the CD&M segment are as follows:

Years ended Dec. 31	**2006**	2005	2004
Revenues	**$ 184.6**	$ 231.0	$ 244.5
Trading purchases	**(118.9)**	(174.1)	(197.7)
Gross margin	**65.7**	56.9	46.8
Operations, maintenance and administration	**36.9**	38.5	31.3
Depreciation and amortization	**1.3**	1.7	2.0
Intersegment cost allocations	**(27.8)**	(26.0)	(26.0)
Operating expenses	**10.4**	14.2	7.3
Prior period regulatory decision	**–**	–	22.9
Operating income	**$ 55.3**	$ 42.7	$ 16.6

For the year ended Dec. 31, 2006, gross margins increased $8.8 million compared to 2005 due to timing and management of positions in the western region, partially offset by lower margins in the eastern region.

Gross margins increased $10.1 million in 2005 compared to the same period in 2004 primarily due to strong results from trading activities in the western region and gains on gas positions throughout the year.

For the year ended Dec. 31, 2006, OM&A decreased $1.6 million compared to the same period in 2005 due to fewer projects resulting in lower consulting costs, partially offset by increased trading staff levels.

In 2005, OM&A costs increased over the same period in 2004 due to higher incentive costs as a result of increased margins as well as project consulting expenses incurred during the year.

Depreciation and amortization in 2006 was relatively consistent with 2005 and 2004.

Value at Risk (VAR) and Trading Positions

VAR is a measure to manage earnings exposure for CD&M activities. VAR is the most commonly used metric employed to track the risk of trading positions. A VAR measure gives, for a specific confidence level, an estimated maximum loss over a specified period of time.

VAR is the primary measure used to manage CD&M's exposure to market risk resulting from trading activities. VAR is monitored on a daily basis, and is used to determine the potential change in the value of the corporation's marketing portfolio over a three-day period within a 95 per cent confidence level resulting from normal market fluctuations. Stress tests are performed weekly on both earnings and VAR to measure the potential effects of various market events that could impact financial results, including fluctuations in market prices, volatilities of those prices and the relationships between those prices.

We estimate VAR using the historical variance/covariance approach. Currently, there is no uniform energy industry methodology for estimating VAR. An inherent limitation of historical variance/covariance VAR is that historical information used in the estimate may not be indicative of future market risk. See additional discussion under commodity price risk in the Risk Factors and Risk Management section.

TransAlta's fixed price trading positions were as follows:

	Electricity	Natural gas
Units (thousands)	(MWh)	(GJ)
Fixed price payor, notional amounts, Dec. 31, 2006	**13,944**	**20,289**
Fixed price payor, notional amounts, Dec. 31, 2005	19,315	11,126
Fixed price receiver, notional amounts, Dec. 31, 2006	**21,536**	**26,231**
Fixed price receiver, notional amounts, Dec. 31, 2005	19,047	12,158
Maximum term in months, Dec. 31, 2006	**33**	**16**
Maximum term in months, Dec. 31, 2005	24	12

Proprietary trading encompasses a range of contractual terms spanning from short-term trading of one to 24 months to longer-term marketing transactions with potential terms greater than 24 months. Changes in trading positions from Dec. 31, 2005 to Dec. 31, 2006 are due to changing market conditions and corresponding regional strategy positioning.

In accordance with EITF 02-03, *Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities,* physical transmission and physical gas in storage are accounted for using accrual accounting. At Dec. 31, 2006, TransAlta recorded prepaid transmission contract assets of $1.6 million compared to approximately $0.8 million at Dec. 31, 2005. The transmission contracts relate to the period from April 2006 to March 2007 and are amortized over this period. Physical transmission is widely used in the California market with a maximum contract term of 12 months. At Dec. 31, 2006, physical gas in storage was recorded at $4.8 million (2005 – $5.2 million). Forward power and gas transactions utilizing physical transmission and gas in storage are accounted for on a mark-to-market basis. While the physical and forward positions economically offset, some unrealized earnings exposure may result in the interim period prior to settlement.

In response to a complaint filed by San Diego Gas & Electric Company under Section 206 of the Federal Power Act (FPA), Federal Energy Regulatory Commission (FERC) established a claim of approximately US$46 million in refunds owing by TransAlta for sales made by it in the organized markets of the California Power Exchange (PX) and the California Independent System Operator (ISO) during the Oct. 2, 2000 through June 20, 2001 period (the Main Refund Transactions). TransAlta has provided US$46 million to account for refund liabilities relating to Main Refund Transactions.

TransAlta filed a cost of service based petition for relief from these refund obligations. FERC rejected TransAlta's relief petition. On Dec. 1, 2006 TransAlta filed for rehearing of FERC's rejection. FERC has not yet issued a decision on rehearing.

During settlement negotiations, the complaintants have sought to obtain refunds for two sets of transactions beyond the Main Refund Transactions. The first set includes sales made by sellers in the PX and ISO markets in the period May to Oct. 1, 2001 (The Summer Transactions). The other set includes bilateral transactions between all sellers and a component of the California Department of Water Resources (CDWR) referred to as CERS (The CERS Transactions). FERC has specifically rejected attempts to introduce refunds for the Summer and CERS Transactions. Nonetheless, the California parties have sought rehearing of FERC's refusal and appealed the refusal to the U.S. Court of Appeals for the Ninth Circuit. TransAlta does not presently believe the California parties will be successful in obtaining refunds alleged for the Summer and CERS transactions. TransAlta has not made any provision for such alleged refunds at this time.

> NET INTEREST EXPENSE AND FOREIGN EXCHANGE

Year ended Dec. 31	2006	2005	2004
Interest on long-term debt	**$ 155.5**	$ 169.3	$ 181.4
Interest on short-term debt	**12.7**	14.9	11.4
Interest on preferred securities	**13.6**	16.5	44.5
Interest income	**(13.3)**	(8.7)	(9.9)
Capitalized interest	**–**	(3.4)	(20.0)
Net interest expense	**$ 168.5**	$ 188.6	$ 207.4

For the year ended Dec. 31, 2006, net interest expense was $20.1 million lower than the comparable period in 2005 due to lower debt levels, higher cash deposits, the impact of the strengthening of the Canadian dollar and the settlement of net investment hedges, partially offset by lower capitalized interest and higher interest rates.

For the year ended Dec. 31, 2005, net interest expense was $18.8 million lower than the same period in 2004 as we redeemed $300.0 million of our preferred securities and replaced them with lower interest rate borrowings. In addition, we reduced overall net debt positions, further reducing our interest costs. Capitalized interest declined as a result of the commissioning of Genesee 3 in March 2005.

> EQUITY LOSS

As required under Accounting Guideline 15, *Variable Interest Accounting,* of the Canadian Institute of Chartered Accountants (CICA), our Mexican operations are accounted for as equity subsidiaries. However, these plants are owned and managed as part of the Generation segment. The table below summarizes availability, production and equity loss from these operations.

Year ended Dec. 31	**2006**	2005	2004
Availability (%)	**90.8**	93.4	88.2
Production (GWh)	**2,918**	2,751	3,164
Equity loss	**$ (17.0)**	$ (0.9)	$ (8.5)

Availability decreased for the year ended Dec. 31, 2006 compared to the same period in 2005 as a result of higher planned outages at the Chihuahua plant. In 2005, availability increased compared to the same period in 2004 due to lower unplanned outages at the Chihuahua facility.

In 2006, production increased 167 GWh compared to 2005 due to increased customer demand, partially offset by higher planned and unplanned outages. In 2005, production decreased 413 GWh compared to 2004 due to lower customer demand.

For the year ended Dec. 31, 2006, equity loss increased $16.1 million compared to 2005 due to recognition of the deferred financing fees resulting from the repayment of non-recourse debt and settlement of interest rate swaps by our equity investees.

For the year ended Dec. 31, 2005, equity loss declined from $8.5 million in 2004 to $0.9 million in 2005 as a result of the strengthening of the Canadian dollar, partially offset by the benefit of higher availability.

> INCOME TAXES

Year ended Dec. 31	**2006**	2005	2004
		(Restated, Note 1)	*(Restated, Note 1)*
(Loss) earnings before income taxes	**$ (80.9)**	$ 213.9	$ 206.2
Adjustments:			
Coal inventory writedown	**44.4**	–	–
Mine closure charges	**191.9**	–	–
Asset impairment charges	**130.0**	–	–
Turbine impairment	**9.6**	–	–
Prior period regulatory decision	**–**	–	22.9
Total adjustments	**375.9**	–	22.9
Earnings before income taxes and adjustments[1]	**$ 295.0**	$ 213.9	$ 229.1
Income tax expense	**61.2**	52.6	69.2
Resolution of uncertain tax positions	**–**	(13.0)	(6.8)
Income tax recovery on adjustments	**(131.7)**	–	(8.0)
Change in tax rate related to prior periods	**(55.3)**	–	(7.8)
Income tax (recovery) expense per financial statements	**$ (125.8)**	$ 39.6	$ 46.6
Effective tax rate (%)	**20.7**	24.6	30.2

1 *Earnings before income taxes and adjustments is not defined under GAAP. Refer to the Non-GAAP Measures section on page 61 of this MD&A for a further discussion.*

Tax expense decreased $165.4 million in the year ended Dec. 31, 2006 compared to the same period in 2005 due to the reduction in the Canadian corporate tax rate, a change in the mix of jurisdictions in which pre-tax income is earned and a reduction in pre-tax earnings as a result of impairment and mine closure charges.

Income tax expense for 2005 was $7.0 million lower than the comparable period in 2004 due to the inclusion of $13.0 million in income tax recovery related to a favourable settlement of outstanding disputes with income tax authorities in 2005. In 2004, a $6.8 million tax settlement at our New Zealand operations was also included in income.

Adjusting for these above-mentioned items, our effective income tax rate was 20.7 per cent for 2006, compared to 24.6 per cent in 2005 and 30.2 per cent in 2004.

> NON-CONTROLLING INTERESTS

Year ended Dec. 31		2006		2005		2004
Non-controlling interests	$	**51.5**	$	18.5	$	46.0

In 2006, non-controlling interests increased $33.0 million from the same period in 2005. Excluding the impairment charge recorded in 2005, non-controlling interests decreased $3.2 million compared to the same period in 2005 due to higher earnings at TA Cogen in 2005. Non-controlling interests for the year ended Dec. 31, 2005, was $27.5 million lower than for the same period in 2004 due to the impairment of the Ottawa facility mentioned above. Adjusting for this amount, non-controlling interests increased $8.7 million from 2004 due to the reduction in our ownership in TA Power and in the Meridian cogeneration facility.

> CONSOLIDATED BALANCE SHEETS

The following chart outlines significant changes in the consolidated balance sheets between Dec. 31, 2006 and Dec. 31, 2005:

	Increase/ (Decrease)	Explanation
Cash and cash equivalents	$ (13.7)	Refer to Consolidated Statements of Cash Flows
Accounts receivable	24.9	Timing of collections in Generation
Inventory	29.9	Higher inventory balances at Centralia Coal
Restricted cash	341.5	Investment in Notes held in trust
Investments	(259.8)	Reduction in investments due to increase in external debt by equity investee
Long-term receivables	32.2	Revised ARO estimate
Property, plant and equipment, net	(509.6)	Reclassification of Centralia Coal mine assets to Assets held for sale, impairment of Centralia Gas assets, increased depreciation, and impact of strengthening of the Canadian dollar compared to the U.S. dollar, partially offset by capital additions
Assets held for sale, net	109.8	Centralia Coal mine assets
Intangible assets	(51.6)	Normal amortization and strengthening of the Canadian dollar compared to the U.S. dollar
Net price risk management assets (including current portion)	40.9	Change in mark-to-market values
Other assets (including current portion)	(63.0)	Realized gain on settlement of net investment hedges and mark-to-market changes on hedging derivatives
Short-term debt	348.8	Net increase in short-term debt
Accounts payable and accrued liabilities	(148.4)	Timing of major maintenance activities offset by increased CD&M activities
Recourse long-term debt (including current portion)	(354.7)	Debt repayments and stronger Canadian dollar compared to the U.S. dollar
Non-recourse long-term debt (including current portion)	(29.5)	Scheduled debt repayments
Deferred credits and other long-term liabilities (including current portion)	108.1	Revised ARO estimates and Centralia mine closure charges
Net future income tax liabilities (including current portions)	(161.6)	Reduction in tax rates and net losses from the period
Non-controlling interests	(23.6)	Distributions in excess of earnings
Shareholders' equity	(69.1)	Net earnings for the period and dividends offset by dividend reinvestment program and share issuances

> PRICE RISK MANAGEMENT

Our price risk management assets and liabilities represent the value of unsettled (unrealized) proprietary trading transactions and certain asset-backed trading transactions accounted for on a fair value basis. With the exception of transmission contracts, the fair value of all energy trading activities is based on quoted market prices. The fair value of financial transmission contracts is based upon statistical analysis of historical data. All transmission contracts are accounted for in accordance with EITF 02-03. The following tables show the balance sheet classifications for price risk management assets and liabilities as well as the changes in the fair value of the net price risk management assets for the period:

Year ended Dec. 31	2006	2005
Balance Sheet		
Price risk management assets		
Current	**$ 61.0**	$ 63.8
Long-term	**21.9**	13.8
Price risk management liabilities		
Current	**(30.3)**	(58.3)
Long-term	**(1.0)**	(8.6)
Net price risk management assets outstanding	**$ 51.6**	$ 10.7

	Mark-to-market	Mark-to-model	Total
Change in fair value of net assets			
Net price risk management assets outstanding at Dec. 31, 2005	$ 7.4	$ 3.3	$ 10.7
Contracts realized, amortized, or settled during the period	(3.8)	(4.8)	(8.6)
Changes in values attributable to market price and other market changes	(6.0)	0.3	(5.7)
New contracts entered into during the current calendar year	10.4	0.1	10.5
Changes in values attributable to discontinued hedge treatment of certain contracts	44.7	–	44.7
Net price risk management assets outstanding at Dec. 31, 2006	**$ 52.7**	**$ (1.1)**	**$ 51.6**

At Dec. 31, 2006, our net price risk management assets and liabilities increased $40.9 million compared to Dec. 31, 2005, primarily due to certain contracts at Centralia Coal no longer receiving hedge accounting treatment.

The anticipated timing of settlement of the above contracts over each of the next five calendar years and thereafter is as follows:

	2007	2008	2009	2010	2011 and thereafter	Total
Prices actively quoted	$ 32.9	$ 17.2	$ 1.7	$ 0.9	$ –	$ 52.7
Prices based on models	(2.2)	1.1	–	–	–	(1.1)
	$ 30.7	$ 18.3	$ 1.7	$ 0.9	$ –	$ 51.6

> CONSOLIDATED STATEMENTS OF CASH FLOWS

The following chart outlines significant changes in the consolidated statements of cash flows between Dec. 31, 2006 and Dec. 31, 2005:

Year ended Dec. 31	2006	2005	Explanation
Cash and cash equivalents, beginning of period	**$ 79.3**	$ 101.2	
Provided by (used in):			
Operating activities	**489.6**	619.8	Increased cash earnings more than offset by timing of collections from customers.
Investing activities	**(261.3)**	(242.5)	Capital expenditures of $223.7 million and increase in restricted cash of $333.1 million, partially offset by decrease in equity investments of $226.4 million, realized gains on net investment hedges of $53.9 million and proceeds on sale of assets of $29.4 million. In 2005, cash outflows were primarily due to additions to property, plant and equipment of $325.9 million, partially offset by realized foreign exchange gains on net investments of $89.8 million.
Financing activities	**(243.2)**	(396.3)	Cash used in financing activities increased due to repayment of long-term debt of $396.7 million, distributions to the subsidiaries' non-controlling interests of $74.4 million, dividend payments of $133.9 million and offset by an increase in short-term debt of $348.1 million. In 2005, cash outflows were due to the redemption of preferred securities of $300.0 million, dividends on common shares of $99.2 million, distribution to subsidiaries' non-controlling interests of $77.5 million, repayment of long-term debt of $139.3 million and repayment of short-term debt of $23.6 million, partially offset by the issuance of long-term debt of $200.0 million.
Translation of foreign currency cash	**1.2**	(2.9)	
Cash and cash equivalents, end of period	**$ 65.6**	$ 79.3	

The following chart outlines significant changes in the consolidated statements of cash flows between Dec. 31, 2005 and Dec. 31, 2004:

Year ended Dec. 31	2005	2004	Explanation
Cash and cash equivalents, beginning of period	$ 101.2	$ 123.8	
Provided by (used in):			
Operating activities	619.8	591.2	Increased cash earnings offset by higher working capital requirements.
Investing activities	(242.5)	(57.4)	In 2005, capital expenditures of $325.9 million were offset by realized gains on net investment hedges of $89.8 million. In 2004, cash outflows were primarily due to additions to property, plant and equipment of $345.7 million, partially offset by proceeds on the sale of TA Power partnership units of $116.5 million, long-term receivables of $90.8 million and realized foreign exchange gains on net investments of $47.8 million.
Financing activities	(396.3)	(549.3)	In 2005, cash outflows were due to the redemption of preferred securities of $300.0 million, dividends on common shares of $99.2 million, distribution to subsidiaries' non-controlling interests of $77.5 million, repayment of long-term debt of $139.3 million and repayment of short-term debt of $23.6 million, partially offset by the issuance of long-term debt of $200.0 million. In 2004, cash outflows were due to the net repayment of debt of $367.4 million, dividends on common shares of $135.4 million, and distributions to subsidiaries' non-controlling limited partner of $48.4 million.
Translation of foreign currency cash	(2.9)	(7.1)	
Cash and cash equivalents, end of period	$ 79.3	$ 101.2	

> LIQUIDITY AND CAPITAL RESOURCES

At the corporate level, we raise substantially all capital to be invested in the various business units and affiliated or subsidiary companies from external markets. This strategy allows us to gain access to sufficient capital at the lowest overall cost. Historically, external financing has been obtained from borrowings under credit facilities, proceeds from the disposal of non-core assets and the issuance of debt, preferred securities and equity. Internally, capital is raised through cash flow from operations.

TransAlta's dividends per common share were $1.00 in 2006, 2005 and 2004.

Financing Arrangements

TransAlta raises capital in the Canadian and U.S. markets. TransAlta has the following financing arrangements in place:

- US$1.0 billion shelf registration program; no amount has been issued since its renewal in July 2004. This program was renewed in October 2006 and is valid until November 2008;
- $1.0 billion medium-term note program; $200.0 million was drawn under this program in December 2005. This program remains valid until December 2007;
- A $200.0 million commercial paper program of which $200.0 million was issued at Dec. 31, 2006;
- $1.5 billion committed syndicated bank credit facility, with $556.4 million utilized at Dec. 31, 2006. The facility was renewed in May 2006 and expires in June 2011; and
- $335.0 million of additional bank credit facilities, with $239.2 million utilized at Dec. 31, 2006. All of these bank credit facilities are non-committed.

At Dec. 31, 2006, the corporation had approximately $840 million of credit available from its committed and uncommitted credit facilities.

At Dec. 31, 2006, TransAlta had a working capital ratio of 0.64 compared to 0.73 at Dec. 31, 2005. This decrease in working capital ratio is attributable to an increase in current liabilities as a result of the reclassification of $175.0 million preferred securities to current liabilities which were redeemed in January 2007, offset by an increase in accounts receivable.

TransAlta expects to have sufficient sources of internal and external capital to finance operations and growth.

Long-term funding is provided through the maintenance of investment grade credit ratings and a carefully managed capital structure, which together create a strong balance sheet and ready access to capital markets at competitive rates. Our objective is to manage the maturities of the various securities on issue so that no more than 15 per cent of the total outstanding securities mature in any one year. Our target is to maintain a capital structure and coverage ratios consistent with investment grade credit ratings. Our capital structure consisted of the following components at Dec. 31, 2006, 2005 and 2004:

	2006		2005		2004	
				(Restated, Note 1)		*(Restated, Note 1)*
Debt, net of cash, restricted cash and interest-earning investments	**$ 2,169.3**	**41%**	$ 2,532.5	44%	$ 2,525.5	42%
Preferred securities, including current portion	**175.0**	**3%**	175.0	3%	475.0	8%
Non-controlling interests	**535.0**	**10%**	558.6	10%	616.4	10%
Common shareholders' equity	**2,427.9**	**46%**	2,497.0	43%	2,436.4	40%
	$ 5,307.2	**100%**	$ 5,763.1	100%	$ 6,053.3	100%

At Dec. 31, 2006, our total debt (including non-recourse debt) to invested capital ratio was 40.9 per cent (37.0 per cent excluding non-recourse debt) compared to the Dec. 31, 2005 ratio of 43.9 per cent (including non-recourse debt) (40.2 per cent excluding non-recourse debt).

Additional key financial ratios were as follows:

	2006	2005	2004
		(Restated, Note 1)	*(Restated, Note 1)*
Cash flow to interest[1] (x)	**5.5**	4.7	4.3
Cash flow to total debt[2] (%)	**26.2**	23.0	19.1

1 Cash flow from operations before changes in working capital plus net interest expense divided by interest on recourse and non-recourse debt less interest income.

2 Cash flow from operations before changes in working capital divided by two-year average of total debt.

Contractual repayments of long-term debt, commitments under operating leases, fixed price purchase contracts and commitments under mining agreements are as follows:

	Fixed price gas purchase contracts	Operating leases	Coal supply and mining agreements	Long-term debt	Total
2007	$ 52.2	$ 14.8	$ 183.6	$ 424.7	$ 675.3
2008	54.0	11.1	169.4	157.1	391.6
2009	31.0	9.9	64.4	241.3	346.6
2010	8.2	9.1	20.9	33.0	71.2
2011	8.2	9.2	20.4	251.9	289.7
2012 and thereafter	55.0	79.3	271.6	1,287.8	1,693.7
Total	$ 208.6	$ 133.4	$ 730.3	$ 2,395.8	$ 3,468.1

Centralia Coal has various coal supply and associated rail transport contracts to provide PRB coal for the use in production. At Alberta Thermal, our mines are operated by a third party who is paid a fixed amount to provide a budgeted supply of coal. Both of these amounts are included under coal supply and mining agreements.

In addition, we have entered into a number of long-term power sales and gas purchase and transportation agreements in the normal course of operations as hedges of our operations.

In the normal course of operations, TransAlta, and certain of our subsidiaries, enter into agreements to provide financial or performance assurances to third parties such as guarantees, letters of credit and surety bonds. These agreements are entered into to support or enhance creditworthiness in order to facilitate the extension of sufficient credit for CD&M trading activities, treasury hedging, Generation construction projects, equipment purchases, and mine reclamation obligations.

At Dec. 31, 2006, the corporation had letters of credit outstanding of $234.0 million and US$344.9 million. These letters of credit were issued to counterparties that have credit exposure to the corporation or certain subsidiaries. If the corporation or a subsidiary does not meet the obligations under the contract, the counterparty may present its claim for payment to the financial institution, which in turn will request payment from the corporation. Any amounts owed by the corporation's subsidiaries are reflected in the consolidated balance sheet. All letters of credit expire in 2007 and are expected to be renewed, as needed, in normal course of business.

The corporation has arranged for the issuance of a surety bond in the amount of US$192.0 million (2005 – US$192.0 million) in support of future mine reclamation obligations at the Centralia mine. A provision for retirement obligations is included in deferred credits and other long-term liabilities *(Note 17)*.

We have provided guarantees of subsidiaries' obligations under contracts that facilitate physical and financial transactions in various derivatives. To the extent liabilities related to these guaranteed contracts exist for trading activities, they are included in the consolidated balance sheet. To the extent liabilities exist related to these guaranteed contracts for hedges, they are not recognized on the consolidated balance sheets. The guarantees provided for under all contracts facilitating physical and financial transactions in various derivatives at Dec. 31, 2006 totaled $1.9 billion. In addition, the corporation has a number of unlimited guarantees of subsidiaries' obligations. The fair value of the trading and hedging positions under contracts where TransAlta has a net liability at Dec. 31, 2006, under the limited and unlimited guarantees, was $285.3 million compared to $559.6 million at Dec. 31, 2005.

TransAlta has also provided guarantees of subsidiaries' obligations to perform and make payments under various other contracts. The amount guaranteed under these contracts at Dec. 31, 2006 was $788.3 million, as compared to $645.3 million at Dec. 31, 2005. To the extent actual obligations exist under the performance guarantees at Dec. 31, 2006, they are included in accounts payable and accrued liabilities.

The corporation has approximately $840 million of undrawn collateral available to secure these exposures.

A subsidiary of the corporation has entered into a credit derivative agreement. Under the terms of the agreement, upon any specified credit event by the corporation or any named subsidiary, the counterparty would have the right to deliver senior debt of the corporation or any named subsidiary in return for payment. The debt obligations referenced by this agreement have been included in the consolidated balance sheet and also include US$295 million of loans made to subsidiaries of the corporation.

On Feb. 27, 2007, we had approximately 202.6 million common shares outstanding, plus outstanding employee stock options to purchase 2.2 million shares.

> OFF-BALANCE SHEET ARRANGEMENTS

Disclosure is required of all off-balance sheet arrangements such as transactions, agreements or contractual arrangements with unconsolidated entities, structured finance entities, special purpose entities or variable interest entities that are reasonably likely to materially affect liquidity or the availability of, or requirements for, capital resources. We have no such off-balance sheet arrangements.

Under Canadian GAAP, most derivatives used in hedging relationships are not recorded on the balance sheet *(Note 1(O)* to the consolidated financial statements.) Gains or losses during the term of the hedge are deferred and recognized in earnings in the same period and financial statement caption as the hedged exposure (settlement accounting). The fair values of these derivatives are disclosed in *Note 6* to the consolidated financial statements. We also enter into long-term electricity purchase and sale, gas purchase and transportation agreements in the normal course of operations. These contracts are not recorded on the balance sheet under Canadian GAAP. Under U.S. GAAP, some of these contracts meet the definition of a derivative, and would require mark-to-market accounting, but are eligible for the normal purchase and sale exemption under FASB Statement 133. This exemption is available as electricity cannot be stored in significant quantities, and is also available for physically settled commodity contracts if certain criteria are met.

Information regarding guarantees has been disclosed in the Liquidity and Capital Resources section.

> RELATED PARTY TRANSACTIONS

In August 2006, TransAlta entered into an agreement with CE Gen, whereby TransAlta buys available power from certain CE Gen subsidiaries at a fixed price. In addition, CE Gen has entered into contracts with related parties to provide administrative and maintenance services.

On March 8, 2006, TA Cogen entered into an agreement with TEC, a wholly owned subsidiary of TransAlta, whereby TEC provided a financial fixed-for-floating price swap to TA Cogen at market prices during planned maintenance at Sheerness in the second quarter of 2006. The swap was settled in the second quarter of 2006 and did not have a material effect on the financial statements. TA Cogen is 50.01 per cent owned by TransAlta and TEC is 100 per cent owned by TransAlta.

On March 8, 2005, TA Cogen entered into an agreement with TEC whereby TEC provided a financial fixed-for-floating price swap to TA Cogen during planned maintenance at Sheerness in the second quarter of 2005. This transaction also did not have a material impact on the financial statements.

As discussed in Significant Events in this MD&A, on Dec. 1, 2004, we completed the sale of our 50 per cent interest in the 220 MW Meridian cogeneration facility located in Lloydminster, Saskatchewan, to TA Cogen for fair value of $110.0 million. TA Cogen financed the acquisition through the use of $50.0 million of cash on hand and by the issuance of $30.0 million of units to each of TA Power and TEC. TA Cogen also issued an advance to TEC for $30.0 million. We recorded a gain of $11.5 million after-tax or $0.06 per common share.

For the period November 2002 to November 2007, TA Cogen entered into a transportation swap transaction with TEC. The business purpose of the transportation swap was to provide TA Cogen with the delivery of fixed price gas without being exposed to escalating costs of pipeline transportation for two of its plants over the period of the swap. TransAlta entered into an offsetting contract with an external third party and therefore we have no risk other than counterparty risk.

TA Cogen entered into a fixed-for-floating gas swap transaction with TEC for a 61-month period starting Dec. 1, 2000. The swap transaction provided TA Cogen with fixed price gas for both the Mississauga and Ottawa plants over the period. The floating prices associated with the Mississauga and Ottawa plants' long-term fuel supply agreements were transferred to TEC's account. The notional gas volume in the transaction was the total delivered fuel for both facilities. As consideration and in negotiation, TA Cogen transferred the right to incremental revenues associated with curtailed electrical production and subsequent higher revenue gas sales. At Dec. 31, 2005, the portion of the contract related to the non-controlling interests had a fair value liability of $1.6 million (2004 – $4.9 million). The contract expired on Dec. 31, 2005.

> EMPLOYEE SHARE OWNERSHIP

We employ a variety of stock-based compensation plans to align employee and corporate objectives. At Dec. 31, 2006, 2.2 million options to purchase our common shares were outstanding, with 1.4 million exercisable at the reporting date. At Dec. 31, 2005, 2.9 million options to purchase our common shares were outstanding, with 1.6 million exercisable at the reporting date.

Under the terms of the Performance Share Ownership Plan (PSOP), certain employees receive awards which, after three years, make them eligible to receive a set number of common shares or cash equivalent plus dividends thereon based upon the performance of the corporation relative to companies comprising the S&P/TSX Composite Index. After three years, once PSOP eligibility has been determined, 50 per cent of the common shares may be released to the participant, while the remaining 50 per cent will be held in trust for one additional year. At Dec. 31, 2006, there were 1.2 million PSOP awards outstanding.

Under the terms of the Employee Share Purchase Plan, we extend an interest-free loan to our employees below executive level for up to 30 per cent of the employee's base salary for the purchase of common shares of the corporation from the open market. The loan is repaid over a three-year period by the employee through payroll deductions unless the shares are sold, at which point the loan becomes due on demand. At Dec. 31, 2006, 0.6 million shares had been purchased by employees under this program.

> EMPLOYEE FUTURE BENEFITS

We have registered pension plans in Canada and the U.S. covering substantially all employees of the corporation, its domestic subsidiaries and specific named employees working internationally. These plans have defined benefit and defined contribution options. In Canada, there is a supplemental defined benefit plan for Canadian-based defined contribution members whose annual earnings exceed the Canadian income tax limit. The defined benefit option of the registered pension plan ceased for new employees on June 30, 1998. The latest actuarial valuations of the registered and supplemental pension plans were as at Dec. 31, 2006.

We provide other health and dental benefits to the age of 65 for both disabled members (other post-employment benefits) and retired members (other post-retirement benefits). The latest actuarial valuation of these other plans was as at Dec. 31, 2004.

The supplemental pension plan is an obligation of the corporation. We are not obligated to fund the supplemental plan but are obligated to pay benefits under the terms of the plan as they come due. We have posted a letter of credit in the amount of $45.3 million to secure the obligations under the supplemental plan.

> 2007 OUTLOOK

The following factors will be influenced by, but not limited to, certain risks and uncertainties. For further discussion, see Risk Factors and Risk Management in this MD&A.

Production, Availability and Capacity

Generating capacity is expected to increase slightly due to an uprate at our Sundance coal-fired facility. Production is expected to increase due to lower planned outages and economic dispatch at Centralia Coal.

As future coal requirements for Centralia Coal for the foreseeable future are being fulfilled by coal imported from PRB, Centralia Coal is expected to be derated until the necessary equipment modifications can be made to burn the higher thermal content PRB coal. As a result, overall fleet availability is expected to be slightly lower compared to 2006.

Contracted Production

Exposure to volatility in electricity prices and spark spreads is substantially mitigated through firm-price, long-term electricity sales contracts and hedging arrangements. For 2007, approximately 93 per cent of expected output is contracted, of which a significant portion relates to the Alberta PPAs, which are based on achieving specified availability rates. We continue to manage future price exposure as market liquidity exists.

Our existing production contracts have remaining terms ranging from one to 30 years with a weighted average remaining term of 12 years.

If certain plants do not meet the availability or production targets specified in the PPAs or other long-term contracts, then the corporation must either compensate the purchaser for the loss in the availability of production or suffer a reduction in electrical or capacity payments. Consequently, an extended outage could have a material adverse effect on the business, financial condition, results of operations, or cash flows of the corporation.

Production and gross margins from our merchant gas plants are subject to the changes in spark spreads discussed in the Power Prices section. TransAlta has not entered into fixed commodity agreements for gas for these merchant plants as gas will be purchased coincident in markets where spark spreads are adequate to profitably produce and sell electricity.

Power Prices

Despite year-over-year demand growth and marginal supply additions, electricity prices and spark spreads for 2007 are anticipated to be lower than those observed in 2006 due to weaker natural gas prices in all markets.

Exposure to volatility in electricity prices and spark spreads is substantially mitigated through firm-price, long-term electricity sales contracts and hedging arrangements.

Fuel Costs

Mining coal is subject to cost increases due to increased overburden removal, inflation and diesel commodity prices. Seasonal variations in coal mining are minimized through the application of standard costing. Due to the timing of capital expenditures and increased commodity costs, we expect coal costs at Alberta Thermal to be approximately $30 million higher in 2007 than those seen in 2006. We expect coal costs at Centralia Coal to decrease due to increased blending of less expensive external coal and the writedown of internally produced inventory to market value.

Exposure on gas costs for facilities under long-term sales contracts are minimized to the extent possible through long-term gas purchase contracts or corresponding offsets within revenues. Merchant gas facilities are exposed to the changes in spark spreads, as discussed in the Power Prices section. We have not entered into fixed commodity agreements for gas for these merchant plants as gas will be purchased coincident with spot pricing.

Certain Centralia Contracts

In the fourth quarter of 2006, unrealized gains of $35.5 million were recorded due to discontinued hedge accounting on certain Centralia Coal contracts and on additional contracts at Centralia Coal. These gains were recognized based upon current forward prices. These market prices will change between now and the time at which these contracts settle. Repurchasing these contracts in the market will reduce the position and mark-to-market earnings fluctuations in future periods. The cash flows from these contracts will be recognized in 2007 and beyond.

Operations, Maintenance and Administration Costs

OM&A costs per MWh of installed capacity fluctuate by quarter and are dependent on the timing and nature of maintenance activities. OM&A costs per MWh of installed capacity are anticipated to be higher in 2007 than those seen in 2006 due to higher planned maintenance and reduced economic dispatch at Centralia Coal.

Capital Expenditures

Our capital expenditures are comprised of spending on sustaining our current operations and for growth activities. The two components are described in greater detail below.

Sustaining Expenditures

Sustaining expenditures include planned maintenance, regular expenditures on plant equipment, systems and related infrastructures, as well as investments in our mines. For 2007, our estimate for total sustaining expenditures, excluding Mexico and CE Gen, is between $320 million and $340 million, allocated among:

- $100 – $110 million for routine capital,
- $80 million for mining equipment,
- $55 million for equipment modifications at Centralia Coal and
- $85 – $95 million on planned maintenance as outlined in the following table:

	Coal	Gas and hydro	Total
Capitalized	$ 70–75	$ 15–20	$ 85–95
Expensed	65–70	0–5	65–75
	$ 135–145	$ 15–25	$ 150–170
GWh lost	2,000–2,050	125–150	2,125–2,200

In 2007, we expect to lose approximately 2,125 GWh to 2,200 GWh of production due to planned maintenance. During 2007, we have no major planned maintenance activities in Mexico.

Growth Expenditures

For 2007, our growth expenditures are estimated to be between $255 million and $265 million on expenses related to the Sundance 4 uprate and the development projects at Keephills 3 and in New Brunswick. Financing for these expenditures is expected to be provided by cash flow from operating activities and existing borrowing capacity.

Exposure to Fluctuations in Foreign Currencies

Our strategy is to minimize the impact of fluctuations in the Canadian dollar against the U.S. dollar by offsetting foreign denominated assets with foreign denominated liabilities and foreign exchange contracts. We also have foreign currency expenses, including interest charges, which offset foreign currency revenues.

Corporate Development and Marketing

CD&M's trading activities are focused on real-time and short-term forward markets. Short-term forward markets show indications of increased volatility in the North American natural gas market. We will continue to prudently manage our risk profile utilizing VAR and other measures.

Our objective is for proprietary trading to contribute between $50 million and $70 million in annual gross margin. In 2006, our CD&M segment contributed $65.7 million of gross margin (2005 – $56.9 million; 2004 – $46.8 million).

Net Interest Expense

Net interest expense for 2007 is expected to be lower than in 2006 due to lower debt levels. However, higher interest rates and changes in the value of the Canadian dollar to the U.S. dollar could offset the benefit of lower debt levels.

Income Tax Rate

Income tax rates in 2007 are expected to be consistent with 2006 levels. Assuming a similar geographic distribution of earnings and no material changes in tax rates, we anticipate an effective tax rate for 2007 to be between 23 and 28 per cent.

Non-Controlling Interests

Earnings and cash distributions attributable to non-controlling interests are expected to be similar in 2007 to those seen in 2006.

Cash Flow and Cash Requirements

In 2007, cash will be provided by a combination of cash flow from operating activities and utilization of various credit facilities. Cash will be required for maintenance, additions to PP&E, dividend payments and repayment of short-term and maturing senior debt. In 2007, operating cash flow is expected to be between approximately $650 million and $750 million, capital expenditures are expected to be between $575 million and $605 million including growth, and $425 million of existing debt is scheduled to be repaid.

Liquidity and Capital Resources

With the anticipated increased volatility in power and gas markets, market trading opportunities are expected to increase, which can potentially cause the need for additional liquidity. To mitigate this liquidity risk, the corporation maintains a $1.5 billion committed credit facility and monitors exposures to determine any liquidity requirements.

Change in Law

The Canadian Government introduced its *Clean Air Act* on Oct. 19, 2006, designed to regulate emissions of greenhouse gases and air pollutants. The proposed Act is currently under review in Parliament and may be subject to changes. Targets for emission reductions have not been announced, nor the associated compliance mechanisms, so we are unable to estimate the impact on our operations. Emission targets under the *Clean Air Act* are also anticipated for mercury; however, they are expected to be superseded by provincial standards already in place, requiring a 70 per cent reduction in emissions by 2010. TransAlta is in the process of meeting that requirement.

The PPAs for our Alberta-based coal facilities contain 'Change-in-Law' provisions that allow us the opportunity to recover compliance costs from the PPA customers.

> RISK FACTORS AND RISK MANAGEMENT

TransAlta uses a multi-level risk management oversight structure to manage the corporation's various risk and energy trading exposures.

The Audit and Environment (A&E) Committee provides assistance to the Board of Directors in fulfilling its oversight responsibility relating to the integrity of the corporation's financial statements and the financial reporting process; the systems of internal accounting and financial controls; the internal audit function; the external auditors' qualifications and term and conditions of appointment, including renumeration, independence, performance and reports; and the legal and environmental compliance programs as established by management and the Board of Directors. The A&E Committee approves our Commodity Risk and Financial Exposure Management policies.

Our Exposure Management (EM) Committee is chaired by our Chief Financial Officer and is comprised of the Executive Vice-President of Corporate Development and Marketing, Vice-President and Treasurer, Vice-President Financial Operations, Vice-President and Comptroller, and the Director of Risk Management. The EM Committee is responsible for reviewing, monitoring and reporting on our compliance with approved financial and commodity risk exposure management policies.

The following addresses some, but not all, risk factors that could affect TransAlta's future results. A discussion of critical estimates made in the application of accounting policies is provided in the Critical Accounting Policies and Estimates section that follows.

Commodity Price Risk

We have exposure to movements in certain commodity prices, including the market price of electricity and fuels used to produce electricity in both our electricity generation and proprietary trading businesses.

Our Alberta coal-fired and hydro facilities operate under the Alberta government mandated PPAs which, among other things, establish the price at which power will be supplied. Our long-term contracts specify the price at which electricity, steam and other services are provided. We have also entered into a variety of short- and long-term contracts to minimize our exposure to short-term fluctuations in electricity prices. In 2006, we had approximately 95 per cent of production under short-term and long-term contracts and hedges (2005 – 91 per cent), and 89 per cent (2005 – 82 per cent) of production was contracted for terms greater than one year. In the event of a planned or unplanned plant outage or other similar event, however, we are exposed to changes in electricity prices on purchases of electricity from the market to fulfill our supply obligations under these short- and long-term contracts. We actively seek to mitigate this exposure through continued and proper maintenance of our electricity generating plants, force majeure clauses negotiated in our contracts, trading activities, and insurance.

We buy natural gas and some of our coal to supply the fuel needed to operate our facilities. We are exposed to increases in the cost of such fuels to the extent such increases are greater than the increases in the price we can obtain for the electricity we produce. In 2006, 68 per cent (2005 – 67 per cent) of our cost of gas used in generating electricity was contractually fixed or passed through to our customers and 100 per cent (2005 – 100 per cent) of our purchased coal costs were contractually fixed. Approximately 70 per cent of coal used in electrical generation is from coal reserves owned by TransAlta, thereby limiting our exposure to fluctuations in the market price of coal. The remainder of the coal used is sourced from the PRB in Montana and Wyoming under medium-term contracts.

Our fuel supply and fuel costs for our gas-fired plants are managed with short-, medium- and long-term gas supply contracts, hedging transactions and contractual agreements that provide for the flow-through of gas costs. We believe adequate supplies of natural gas at reasonable prices will be available for plants when existing supply contracts expire. We also continuously monitor the market for opportunities to enter into favourably priced long-term gas contracts.

Higher input costs, such as diesel, tires, the price of mining equipment, increased amounts of overburden being removed to access coal reserves and mining operations moving further away from the power plants are all contributing to increased mining costs to our customers. Additionally, the ability of the mines to deliver coal to the power plants can be impacted by weather conditions and labour relations.

Production and gross margins from our merchant gas plants are subject to changes in spark spreads. We have not entered into fixed commodity agreements for gas for these merchant plants as gas will be purchased concurrent where spot market spark spreads are adequate to produce and sell electricity at a profit.

Our proprietary trading of gas and electricity is limited, strictly controlled and managed through the use of VAR methodologies. VAR is the primary measure used to manage CD&M's exposure to market risk resulting from trading activities as described on page 42 of the MD&A.

Currency Rate Exposure

We have exposure to various currencies as a result of our investments and operations in foreign jurisdictions, the earnings from those operations, and the acquisition of equipment and services from foreign suppliers. We have exposures primarily to the U.S., Mexican and Australian currencies. We limit our exposure to movements in these currencies in two ways. First, we hedge our net investments in foreign operations using a combination of foreign denominated debt and financial instruments. Second, the earnings from our foreign operations are substantially offset by expenditures, including interest expense denominated in the foreign currencies.

At Dec. 31, 2006, we hedged approximately 88.3 per cent (2005 – 96.8 per cent) of our foreign currency translation exposure. Our strategy is to offset 90 to100 per cent of all foreign currency exposures.

Translation gains and losses related to the carrying value of our foreign operations are deferred and included in the cumulative translation adjustment account in shareholders' equity. At Dec. 31, 2006, the balance in this account was a $64.5 million loss (2005 – $67.0 million loss).

Credit Risk

If the counterparties to our contracts are unable to meet their obligations, our revenues could be adversely affected. We manage our exposure to credit risk by assessing the ability of counterparties to fulfill their obligations under the related contracts prior to entering into such contracts. We set credit limits for each counterparty and the mix of counterparties based on their credit ratings. Counterparty exposures for trading activities are monitored daily. If the credit exposure limits are exceeded, we take steps to reduce this exposure such as requesting collateral, if applicable, or by halting trading activity. However, there can be no assurances that we will be successful in avoiding losses as a result of a contract counterparty not meeting its obligations.

We are exposed to minimal credit risk for Alberta PPAs because under the terms of these arrangements, receivables are substantially all secured by letters of credit.

A summary of our credit exposure for trading operations at Dec. 31, 2006, is provided below:

Rating	Net exposure	Number of counterparties greater than 10%	Net exposure of counterparties greater than 10%
Investment grade	$ 71.5	2	$ 19.6
Non-investment grade	–	–	–
No external rating, internally rated as investment grade	12.7	–	–
No external rating, internally rated as non-investment grade	0.1	–	–
	$ 84.3	2	$ 19.6

In addition to the above, we have credit exposure to counterparties under long-term sales contracts.

The maximum credit exposure to any one customer for commodity trading operations, excluding the ISO and PX discussed earlier, and including the fair value of open trading positions, is $11.3 million.

Liquidity Risk

Liquidity risk relates to our commitments to meet collateral requirements under these contracts. We are exposed to liquidity risk under certain electricity and natural gas purchase and sale contracts entered into for the purposes of asset-backed sales and proprietary trading. The terms and conditions of these contracts require us to provide collateral when the fair value of these contracts is in excess of any credit limits granted by our counterparties and the contract obliges us to provide the collateral. The fair value of these contracts change due to changes in commodity prices and foreign exchange rates. These contracts include: (i) purchase agreements, when forward commodity prices are less than contracted prices; and (ii) sales agreements, when forward commodity prices exceed contracted prices. Downgrades in our creditworthiness by certain credit rating agencies may decrease the credit limits granted by our counterparties and accordingly increase the amount of collateral we may have to provide.

The maximum amount of collateral that we would have to provide under existing contracts for our commodity trading operations and with our existing credit ratings is $41.9 million at Dec. 31, 2006. Total collateral available to the corporation was approximately $840 million.

Interest Rate Exposure

Changes in interest rates can impact our borrowing costs and the capacity revenues we receive from our Alberta PPA plants. We address this risk by employing a combination of fixed and floating rate debt instruments. Carrying a proportion of our debt that is exposed to floating interest rates also allows us to take advantage of changes in the market and reduced interest costs. At Dec. 31, 2006, approximately 28.4 per cent (2005 – 24.8 per cent) of the corporation's total debt portfolio was subject to movements in floating interest rates through a combination of floating rate debt and interest rate swaps.

Operational Risk

Our plants are exposed to operational risks such as fatigue cracks in boilers, corrosion in boiler tubing, turbine failures and other issues that can lead to outages. A comprehensive plant maintenance program and regular turnarounds reduce this exposure. If the plants do not meet the availability or production targets specified in the PPAs or other long-term contracts, we must either compensate the purchaser for the loss in the availability of production or suffer a reduction in electrical or capacity payments. For merchant facilities, an extended outage can result in lost merchant opportunities. Therefore, an extended outage could have a material adverse effect on our business, financial condition, results of operations or our cash flows. Insurance and force majeure clauses in the PPAs and other long-term contracts partially mitigate this exposure.

The construction, development and acquisitions of generating facilities are subject to various environmental, engineering and construction risks relating to cost-overruns, delays and performance. We attempt to minimize these risks by performing detailed analysis of project economics prior to construction or acquisition and by securing favourable power sales agreements.

Of the corporation's labour, 56 per cent is covered under 13 collective bargaining agreements. Four agreements were renegotiated in 2006 and we anticipate the renewal of nine agreements in 2007. We do not anticipate any significant issues in the renewal of these agreements.

Our hydro operations financial performance is partially dependent upon the availability of water in a given year. The availability of water is difficult to forecast as it is primarily driven by weather. Such water availability introduces a degree of volatility in revenues earned by our hydro operations from year to year. This risk is complicated by obligations imposed within the PPA applicable to the corporation's Alberta hydro facilities. A monthly financial obligation must be paid to the PPA buyer, based on a predetermined quantity of energy and ancillary services at market prices, regardless of our ability to generate such quantities. We manage these risks on a real-time basis by monitoring water resources throughout Alberta to the best of our ability and optimizing this resource against real-time electricity market opportunities. We also play an important role in the management of water flows and levels in several key areas of Alberta, including two major cities. We carefully balance all of these factors together to achieve optimal productivity with the water resources available.

Our wind and geothermal operations are dependent upon the availability of wind and geothermal resources. While we have placed our facilities in locations which we believe to have sufficient resources in order for us to be able to generate sufficient electricity to meet the requirements of contracts and investors, we cannot guarantee that these resources will be available when we need them or in the quantities that we require.

Environmental, Health and Safety Risk (EHS)

Our approach to managing our EHS risk has four elements:

- compliance-based activities, such as permitting and reporting,
- ISO-based EHS Management systems and programs, such as safety programs and auditing,
- longer-term strategic initiatives, including climate change and government policy development and
- a process for confidentially reporting any potential ethical concerns from employees.

These elements are integrated into our corporate-wide operations and management systems. They are designed to mitigate risks of our activities to employees, the public and the environment, and to address potential competitive risks from future changes in environmental policy. They are also supportive of our corporate commitment to sustainability.

We strive to maintain compliance with all environmental regulations relating to operations and facilities. Quarterly reports on all EHS regulatory changes are provided to each facility to ensure compliance is maintained. As well, we produce and distribute annual public reports on our performance. We seek continuous improvement in numerous performance metrics such as emissions, safety, land and water impacts and environmental incidents.

We have implemented an ISO-based EHS management system, designed to continuously improve environmental and safety performance. All of our plants have implemented the system, with one plant having an equivalent variation as required by our partner. Compliance with both regulatory requirements and management system standards is regularly audited through our Performance Assurance policy and results are reported quarterly to our Board of Directors. In 2006, TransAlta spent approximately $49 million (2005 – $47 million) on environmental management.

TransAlta commits significant effort to work with regulators in Canada and the United States. to ensure regulatory changes are well-designed and cost-effective. New emission reduction objectives for the power sector are being established by governments in Canada and the United States. We have compliance plans over the next decade for greenhouse gases, mercury, sulphur dioxide and oxides of nitrogen, which will be adjusted as regulations are finalized. Where capital investment for control equipment may be required, we have technology review processes underway.

TransAlta has implemented a four-component strategy on climate change that manages future regulation risk and develops competitive business advantages. The cornerstones of the strategy are:

- Internal operational improvements that lower the emissions of our generation operations. These improvements include plant upgrades, intensive equipment maintenance, efficiency improvements and fuel decision choices.
- Purchase of emission reduction offsets outside our operations. TransAlta has been a leader in Canada in this area and has created an offsets portfolio that will assist us in meeting emission targets at a competitive cost.
- Renewable energy investments, such as in wind capacity, which reduce our emissions intensity and diversify our fuel mix.
- Investments in clean coal technology development, which provides long-term promise for large emission reductions from fossil-fired generation. TransAlta is a founder of the Canadian Clean Power Coalition, which is an industry consortium developed to build Canada's first clean coal power plant.

We anticipate continued and growing scrutiny by investors relating to sustainability performance. The Dow Jones Sustainability Index has again recognized TransAlta as one of the world's best utility companies in terms of sustainability performance, for the eighth year in a row. In Alberta, we are preparing to install mercury capture equipment at our coal-fired plants to achieve a 70 per cent reduction of mercury emissions by 2010. The exact technology and performance requirements have not yet been finalized; however, TransAlta will soon begin long-term, full-scale testing of technology to reduce mercury emissions. Our PPAs will also provide an opportunity to recover these costs under 'Change-in-Law' provisions. In the United States, our Centralia plant may also be subject to mercury reduction requirements within the next five to seven years.

We are dedicated to operating a safe and ethical organization. We have a system in place where employees may report any potential ethical concerns. These concerns are directed to the Director, Corporate Security and Corporate Secretary where any follow-up or action is initiated.

Regulatory and Political Risk

Certain of the markets in which the corporation operates are subject to significant regulatory oversight and control. The corporation is not able to predict whether there will be any changes in the regulatory environment or the ultimate effect of changes in the regulatory environment on its business. TransAlta manages these risks by working with governments, regulators and other stakeholders to attempt to resolve issues. In Ontario, new Legislation was passed in December 2004 outlining a new electricity market structure. The new market design provides for a mix of: i) regulated assets, ii) unregulated assets and iii) government-backed long-term contracts. TA Cogen's assets have retained their existing government contracts in the restructured market. On Feb. 14, 2006, TransAlta signed a five-year contract with the Ontario Power Authority for its Sarnia cogeneration plant. Under the terms of the contract, the plant will be available to supply an average of 400 MW of power to the Ontario electricity market. New generation in Ontario will continue to be procured by the government and backed by government contracts. In Alberta, TransAlta received regulatory approval in November 2006 for a 53 MW capacity increase at its Sundance 4 generating unit. The increase will be operational in late 2007. TransAlta also received regulatory approval on Feb. 14, 2007 for a new 450 MW unit at its Keephills power plant. The new unit will be commissioned in 2011 and is 50 per cent owned by EPCOR.

Also in Alberta, a wholesale market review task force and a retail market review were initiated in 2004 to evaluate the functioning of the electricity market and to consider market design changes. A market design policy recommendation was completed in 2005. It supported the continuation of an energy-only market in Alberta along with a number of rule changes related to reliability and short-term adequacy. In 2006, several of these changes were implemented and others are expected during 2007. The Alberta Department of Energy is undertaking a review of the regulation and rules associated with Market Power. That review is expected to be complete by June 2007. The outcome of this Market Power committee's work is important to TransAlta as it may include, but is not limited to: increased compliance, growth restrictions in Alberta, increased operating or capital costs, reduced operational flexibility or reduced power prices and volatility.

International investments are subject to unique risks and uncertainties relating to the political, social and economic structures of the respective country and such country's regulatory regime. The corporation may mitigate this risk through the use of non-recourse financing and political risk insurance.

Transmission Risks

In August 2003, a blackout cut off electricity to millions of residents in the Northeastern United States and Eastern Canada. This type of event, although extremely unusual, is an ongoing risk for electric companies. This risk is mitigated through force majeure clauses in the Alberta PPAs and power sales contracts and access to multiple transmission lines.

Transmission constraints are a risk for generators as they can result in curtailment of output at generation facilities and may restrict development and interconnection of future generation facilities. This risk is managed by working with governments, regulators and stakeholders to ensure that transmission constraints are removed through timely transmission development or technology additions.

Corporate Structure

We conduct a significant amount of business through subsidiaries and partnerships. Our ability to meet and service debt obligations is dependent upon the results of operations of our subsidiaries and the payment of funds by such subsidiaries to the corporation in the form of distributions, loans, dividends or otherwise. In addition, our subsidiaries may be subject to statutory or contractual restrictions that limit their ability to distribute cash to the ultimate shareholder, the corporation.

General Economic Conditions

Changes in general economic conditions impact product demand, revenue, operating costs, the timing and extent of capital expenditures, the net recoverable value of PP&E, results of financing efforts, credit risk and counterparty risk.

Income Taxes

Our operations are complex, and the computation of the provision for income taxes involves tax interpretations, regulations and legislation that are continually changing. Our tax filings are subject to audit by taxation authorities. Management believes that it has adequately provided for income taxes based on all information currently available.

Legal Contingencies

We are occasionally named as a defendant in various claims and legal actions. Exposure to these claims is mitigated through levels of insurance coverage considered appropriate by management and active management of these claims. Except as disclosed in *Note 22* to the consolidated financial statements, the corporation does not expect the outcome of the claims or potential claims to have a materially adverse effect on the corporation as a whole.

Other Contingencies

The corporation maintains a level of insurance coverage deemed appropriate by management. There were no significant changes to our insurance coverage during 2006. The corporation's insurance coverage may not be available in the future on commercially reasonable terms. There can be no assurance that insurance proceeds received by the corporation for any loss or damage will be sufficient.

Sensitivity Analysis

The following table shows the after-tax effect on net earnings and cash flows of changes in certain key variables. The analysis is based on business conditions and production volumes in 2006. Each separate item in the sensitivity assumes the others are held constant. While these sensitivities are applicable to the period and magnitude of changes on which they are based, they may not be applicable in other periods, under other economic circumstances, or for greater magnitude of changes.

Sensitivities

	Approximate impact	
Factor	Increase or decrease	Earnings and cash flow (after-tax) (millions)
Electricity price	$1.00/MWh	$ 8.5
Natural gas price	$0.1/GJ	1.3
Availability/production	1%	16.7
Exchange rate (US$ per Cdn$)	US$0.01	1.4
Interest rate	1%	6.2
Tax rate	1%	4.3

The impact of a $1.00 per MWh change in electricity prices has minimal impact on our after-tax cash flow and earnings, as approximately 95 per cent of output is at contractually fixed prices through short-term or long-term contracts and hedges. A change in natural gas prices also has minimal impact as substantially all of our gas costs have been contractually fixed or flow through to customers under terms of agreements.

The calculation of the impact of a one per cent change in availability assumes that production levels will change by an equivalent amount at the contracted plants. An increase in availability at the merchant gas plants may not result in increased production.

Our hedging strategies have minimized the impact of changes in exchange rates and interest rates as our net investments in foreign operations have been hedged and interest rates on approximately 71.6 per cent of our debt have been fixed.

The income tax rate can change depending on the mix of earnings from various countries. Increased operating income will incur income tax expense at a rate of approximately 32 per cent compared to the forecasted overall range of 23 to 28 per cent.

> NEW ACCOUNTING STANDARDS

Effective Jan. 1, 2006, TransAlta early adopted the CICA Emerging Issues Committee (EIC) Abstract 160 *Stripping Costs Incurred in the Production of a Mining Operation* (EIC-160). Under EIC-160, stripping costs to remove overburden and waste materials to access mineral deposits should be accounted for as variable production costs during the period that the stripping costs are incurred. Previously, a portion of the stripping costs would have been carried forward to future periods as part of inventory or prepaid expenses.

We have considered costs incurred during 2005 and previous years that meet the definition of stripping costs under EIC-160. Factors considered in the analysis include stripping costs, tons of coal produced, and whether the stripping costs could be capitalized.

As a result of this review, we determined that costs incurred during 2005 and previous years did meet the definition of stripping costs under EIC-160 and therefore stripping costs have been accounted for as period costs. Prior periods have been restated to reflect this change in accounting policy. The 2005 after-tax impact of the adjustment was $12.5 million ($0.06 per common share). Prepaid assets and inventory were reduced by $66.0 million and $4.6 million, respectively. For the year ended Dec. 31, 2004, the after-tax impact of the adjustment was $1.0 million ($nil per common share).

In January 2005, the CICA issued four new accounting standards that are effective for interim and annual financial statements relating to fiscal years beginning on or after Oct. 1, 2006. These new standards include Section 1530, *Comprehensive Income,* Section 3251, *Equity,* Section 3855, *Financial Instruments – Recognition and Measurement* and Section 3865, *Hedges.* The corporation adopted these standards as of Jan. 1, 2007. These standards are expected to have a minimal impact on the presentation of the financial statements.

In July 2006, the FASB issued Interpretation No. 48, *Accounting for Uncertainty in Income Taxes, an Interpretation of FASB Statement No. 109* (FIN 48). FIN 48 is intended to provide a single model to address accounting for uncertain tax positions by establishing a recognition threshold and measurement for tax positions taken or expected to be taken in a tax return. Further, clarification on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition is also provided. The guidance in FIN 48 is effective for fiscal years beginning after Dec. 15, 2006. The corporation will adopt FIN 48 as of Jan. 1, 2007, as required. The corporation is currently assessing the impact of the adoption of FIN 48.

In July 2006, the EIC issued EIC-162, *Stock-based compensation for employees eligible to retire before the vesting date* (EIC-162). This abstract accelerates the recognition of compensation costs for stock-based awards based on the retirement eligibility of the employee at the grant date and during the vesting period. EIC-162 is effective for interim and annual periods ending on or after Dec. 31, 2006 and should be applied retroactively. We adopted this standard effective in the fourth quarter of 2006. Comparative balances have not been restated as the impact on prior periods is not significant.

In June 2006, the EITF issued EITF Issue No. 06-2 *Accounting for Sabbatical Leave and Other Similar Benefits Pursuant to FASB Statement* No. 43, *Accounting for Compensated Absences* (Issue No. 06-2). Under Issue No. 06-2, a company should accrue for sabbatical leave or other similar benefits if the employee is required to complete a minimum service period to be entitled to the benefit, there is no increase to the benefit if the employee provides additional years of service, the employee continues to be a compensated employee during his/her absence and the employer does not require the employee to perform any duties during his/her absence. Issue No. 06-2 is effective for fiscal years beginning after Dec. 15, 2006. TransAlta has evaluated the accounting guidance and has adopted the consensus effective Jan. 1, 2007. Comparative balances have not been restated as the impact on prior periods is not significant.

In September 2006, the FASB issued *Statement of Financial Accounting Standards* (SFAS) No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans* – an amendment of FASB Statements No. 87, 88, 106, and 132(R) (SFAS 158). SFAS 158 requires companies to report the funded status of their defined benefit pension plans on the balance sheet with changes in the funded status recognized in other comprehensive income in the year of the change. SFAS 158 also requires additional disclosure. SFAS 158 is effective for years ending after Dec. 15, 2006. TransAlta has adopted the requirements of SFAS 158 and the results have been reflected in the U.S. GAAP reconciliation *(Note 30).*

> CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The selection and application of accounting policies is an important process that has developed as our business activities have evolved and as accounting rules have changed. Accounting rules generally do not involve a selection among alternatives, but involve an implementation and interpretation of existing rules and the use of judgment relative to the circumstances existing in the business. Every effort is made to comply with all applicable rules on or before the effective date, and we believe the proper implementation and consistent application of accounting rules is critical.

However, not all situations are specifically addressed in the accounting literature. In these cases, our best judgment is used to adopt a policy for accounting for these situations. We draw analogies to similar situations and the accounting guidelines governing them, consider foreign accounting standards, and consult with our independent auditors about the appropriate interpretation and application of these policies. Each of the critical accounting policies involves complex situations and a high degree of judgment either in the application and interpretation of existing literature or in the development of estimates that impact the corporation's consolidated financial statements.

Our significant accounting policies are described in *Note 1* to the consolidated financial statements. The most critical of these policies are those related to revenue recognition, PP&E, goodwill, asset retirement obligations, income taxes and employee future benefits *(Notes 1(C), (F), (G), (I), (L)* and *(M)*, respectively). Each policy involves a number of estimates and assumptions to be made about matters that are highly uncertain at the time the estimate is made. Different estimates, with respect to key variables used for the calculations, or changes to estimates, could potentially have a material impact on our financial position or results of operations.

We have discussed the development and selection of these critical accounting estimates with our A&E Committee and our independent auditors. The A&E Committee has reviewed and approved our disclosure relating to critical accounting estimates in this MD&A.

Tables are provided in the following discussion to reflect the sensitivities associated with changes in key assumptions used in the estimates. The tables reflect an increase or decrease in the percentage or other factor for each assumption. The inverse of each change is generally expected to have a similar opposite impact. Each separate item in the sensitivity assumes all other factors remain constant.

These critical accounting estimates are described below.

Revenue Recognition

The majority of our revenues are derived from the sale of physical power and from energy marketing and trading activities. Revenues under long-term electricity and thermal sales contracts generally include one or more of the following components: fixed capacity payments for being available, energy payments for generation of electricity, availability incentives or penalties for exceeding or not meeting availability targets, excess energy payments for power generation above committed capacity and ancillary services. Each of these components is recognized upon output, delivery or satisfaction of contractually specific targets. Revenues from non-contracted capacity are comprised of energy payments for each MWh produced at market prices and are recognized upon delivery.

Trading activities use derivatives such as physical and financial swaps, forward sales contracts and futures contracts and options, which are used to earn trading revenues and to gain market information. These derivatives are accounted for using fair value accounting. Derivatives, other than real-time physical contracts, are presented on a net basis in the statements of earnings. The initial recognition of fair value and subsequent changes in fair value affect reported earnings in the period the change occurs. The fair values of those instruments that remain open at the balance sheet date represent unrealized gains or losses and are presented on the balance sheets as price risk management assets or liabilities. Non-derivative contracts are accounted for using the accrual method. To be consistent with the EITF 03-11, TransAlta has concluded that real-time physical contracts meet the definition of derivative contracts held for delivery and therefore realized gains and losses are reported gross in the statements of earnings.

The determination of the fair value of energy trading contracts and derivative instruments is complex and relies on judgments concerning future prices, volatility and liquidity, among other factors. The majority of derivatives traded by TransAlta have quoted market prices or over-the-counter quotes available from brokers. However, some derivatives are not traded on an active exchange or extend beyond the time period for which exchange-based quotes are available. These derivatives require the use of internal valuation techniques or models (mark-to-model accounting).

Mark-to-model accounting is currently used for physical and financial forward contracts and option contracts on transmission and transmission congestion. Accrual accounting is used for transmission rights acquired to sell production from our plants and physical transmission rights used by the CD&M segment. Changes in fair value of derivatives subsequent to inception are recorded on the consolidated balance sheets as price risk management assets or liabilities with the offset recorded in revenues. The values can be favourable or unfavourable, and depending on current market conditions, values can fluctuate significantly with the effect of changes being recorded through earnings in the period of the change. Modeling techniques require the corporation to model future prices, price correlation, market volatility, liquidity and other forecasted market intelligence, as well as the use of mathematical extrapolation techniques. Where appropriate, the estimates used to derive fair value reflect the potential impact for uncertainties in the modeling process, the potential impact of liquidating the corporation's position in an orderly manner over a reasonable period of time under present market conditions and operational risk. We validate our mark-to-model results by comparing them against settled data. The amounts reported in the financial statements may change as estimates are revised to reflect actual results or new information, changes in market conditions, or other factors, many of which are beyond our control, and may be material.

Key variables used in the models are uncertain. The estimated value of these contracts at Dec. 31, 2006 using mark-to-model methodology was $1.1 million. Sensitivities of the valuation, which would have been recorded in earnings in the current year, are as follows:

Assumption	Change in assumption	Impact on pre-tax earnings
Change in volatility	1%	$ 0.4
Change in commodity price	1%	$ 1.2

There have been no significant changes to the modeling techniques in the past three years.

Valuation of PP&E

PP&E makes up 67.6 per cent of our assets, of which 99 per cent relates to the Generation segment. On an annual basis, and when indicators of impairment exist, we determine whether the net carrying amount of PP&E is recoverable from future undiscounted cash flows. Factors which could indicate that an impairment exists include significant underperformance relative to historical or projected operating results, significant changes in the manner or use of the assets, the strategy for the corporation's overall business and significant negative industry or economic trends. In some cases, these events are clear. However, in many cases, a clearly identifiable event indicating possible impairment does not occur. Instead, a series of individually insignificant events occur over a period of time leading to an indication that an asset may be impaired. This can be further complicated in situations where we are not the operator of the facility. Events can occur in these situations that may not be known until a date subsequent to their occurrence.

Our businesses, the markets and the business environment are continually monitored, and judgments and assessments are made to determine whether an event has occurred that indicates possible impairment. If such an event has occurred, an estimate is made of the future undiscounted cash flows from the asset. If the total of the undiscounted future cash flows (excluding financing charges, with the exception of plants that have specifically dedicated debt), is less than the carrying amount of the asset, an asset impairment charge must be recognized in our financial statements. The amount of the impairment recognized is calculated by subtracting the fair value of the asset from the carrying value of the asset. Fair value is the amount at which an item could be bought or sold in a current transaction between willing parties, and is best estimated by calculating the net present value of future expected cash flows related to the asset. Both the identification of events that may trigger an impairment and the estimates of future cash flows and the fair value of the asset require considerable judgment.

The assessment of asset impairment requires management to make significant assumptions about future sales prices, cost of sales, production and fuel consumed over the life of the plants (up to 30 years), retirement costs and discount rates. In addition, when impairment tests are performed, the estimated useful lives of the plants are reassessed, with any change accounted for prospectively.

In estimating future cash flows of the plants, we use estimates of contracted and future market prices based on expected market supply and demand in the region in which the plant operates, anticipated production levels, planned and unplanned outages, and transmission capacity or constraints for the remaining life of the plant. Actual results can, and often do, differ from the estimates, and can have either a positive or negative impact on the estimate of the impairment charge, and may be material.

On an annual basis, or as events indicate, we perform an impairment review of our plants. As a result of this review, in 2006 we recorded an impairment charge for the Centralia Gas plant as the full book value of this plant was unlikely to be recovered from future cash flows due to changes in outlook for dispatch rates and trading values and their impact on plant profitability *(Note 3).*

As a result of the decision to stop mining at the Centralia Coal mine, we wrote down mining and reclamation equipment as well as mining infrastructure to the lower of net book value and fair value *(Note 2).*

In 2005, we determined that the Ottawa plant was impaired in the accounts of TA Cogen. A fundamental shift in the gas markets and forecast increases in the cost of natural gas lowered expected margins from the Ottawa plant as TA Cogen does not have a gas supply contract in place for the period 2008 – 2012 to match the contract to provide electricity under predetermined prices to the Ontario Electricity Financial Corporation (OEFC). Based upon the current view of gas costs and market conditions for that period and the likelihood that the plant will not operate as extensively beyond 2012, a reduction in the carrying value was required and a charge of $36.2 million was recognized in 2005. The discussion of significant events discloses our treatment of this item.

From the results of our current impairment review, had assumptions been made that resulted in future cash flows of the plants declining by 10 per cent, none of our plants would have been impaired at Dec. 31, 2006.

Asset Retirement Obligations

We recognize AROs for PP&E in the period in which they are incurred if there is a legal obligation for us to reclaim the plant and/or site and if a reasonable estimate of a fair value can be determined. The fair value of the liability is described as the amount at which the liability could be settled in a current transaction between willing parties. Expected values are probability weighted to deal with the risks and uncertainties inherent in the timing and amount of settlement of many AROs. Expected values are discounted at the risk-free interest rate adjusted to reflect the market's evaluation of the entity's credit standing.

At Dec. 31, 2006, the AROs recorded on the consolidated balance sheets were $328.5 million. We estimate the undiscounted amount of cash flow required to settle the AROs is approximately $1.1 billion, which will be incurred between 2008 and 2012. The majority of the costs will be incurred between 2020 and 2030. A discount rate of eight per cent was used to calculate the carrying value of the AROs.

Sensitivities for the major assumptions are as follows:

Assumption	Change in assumption	Impact on pre-tax earnings
Discount rate	1%	$ 3.3
Undiscounted AROs	1%	$ 0.3

Useful Life of PP&E

PP&E is depreciated over its estimated useful life. Estimated useful lives were determined based on current facts and past experience, and take into consideration the anticipated physical life of the asset, existing long-term sales agreements and contracts, current and forecasted demand and the potential for technological obsolescence. Major components of plants are depreciated over their own useful lives. A component is a tangible asset that can be separately identified as an asset and is expected to provide a benefit of greater than one year.

Depreciation and amortization expense was $437.8 million in 2006, of which $49.0 million relates to mining equipment, and is included in fuel and purchased power.

The rates used are reviewed on an ongoing basis to ensure they continue to be appropriate, and are also reviewed in conjunction with impairment testing, as discussed above.

A five per cent change in the estimated useful life of depreciable assets will result in a change of $19.2 million in depreciation and amortization expense.

Valuation of Goodwill

We evaluate goodwill for impairment at least annually or more frequently if indicators of impairment exist. If the carrying value of a reporting unit, including goodwill, exceeds the reporting unit's fair value, any excess represents a goodwill impairment loss. A reporting unit is a portion of the business for which we can identify specific cash flows.

Goodwill was recorded on the acquisitions of Merchant Energy Group of the America, Vision Quest and CE Gen. At Dec. 31, 2006, this goodwill had a total carrying value of $137.5 million.

We reviewed the recorded value of goodwill and determined that the fair values of our reporting units, based on historical cash flows and estimates of future cash flows, exceeded their carrying values and therefore no impairment charges were recorded.

Determining the fair value of the reporting units is susceptible to changes from period to period as management is required to make assumptions about future cash flows, production and trading volumes, margins and fuel and operating costs. Had assumptions been made that resulted in fair values of the reporting units declining by 10 per cent from current levels, there would not have been any impairment of goodwill.

Income Taxes

In accordance with Canadian GAAP, we use the liability method of accounting for future income taxes and provide future income taxes for all significant income tax temporary differences.

Preparation of the consolidated financial statements requires an estimate of income taxes in each of the jurisdictions in which we operate. The process involves an estimate of our actual current tax exposure and an assessment of temporary differences resulting from differing treatment of items, such as depreciation and amortization, for tax and accounting purposes. These differences result in future tax assets and liabilities which are included in our consolidated balance sheets.

An assessment must also be made to determine the likelihood that our future tax assets will be recovered from future taxable income. To the extent that recovery is not considered likely, a valuation allowance must be determined. Judgment is required in determining the provision for income taxes, future income tax assets and liabilities, and any related valuation allowance. To the extent a valuation allowance is created or revised, current period earnings will be affected.

Future tax assets of $319.8 million have been recorded on the consolidated balance sheets at Dec. 31, 2006. These assets are comprised primarily of unrealized losses on electricity trading contracts, asset retirement obligation costs, and net operating and capital loss-carry-forwards. We believe there will be sufficient taxable income and capital gains that will permit the use of these deductions and carryforwards in the tax jurisdictions where they exist.

Future tax liabilities of $718.5 million have been recorded on the consolidated balance sheets at Dec. 31, 2006. These liabilities are comprised primarily of unrealized gains on electricity trading contracts and income tax deductions in excess of related depreciation of PP&E.

Judgment is required to assess continually changing tax interpretations, regulations and legislation, to ensure liabilities are complete and to ensure assets, net of valuation allowances, are realizable. The impact of different interpretations and applications could be material.

Our tax filings are subject to audit by taxation authorities. The outcome of some audits may change the tax liability of the corporation, although we believe that we have adequately provided for income taxes based on all information currently available. The outcome of the audits is not known nor is the potential impact on the financial statements determinable.

Employee Future Benefits

As explained in *Note 26* to the consolidated financial statements, we provide post-retirement benefits to employees. The cost of providing these benefits is dependent upon many factors that result from actual plan experience and assumptions of future experience.

The liability for future benefits and associated pension costs included in annual compensation expenses are impacted by employee demographics, including age, compensation levels, employment periods, the level of contributions made to the plans and earnings on plan assets.

Changes to the provisions of the plans may also affect current and future pension costs. Pension costs may also be significantly impacted by changes in key actuarial assumptions, including anticipated rates of return on plan assets and the discount rates used in determining the projected benefit obligation and pension costs.

The plan assets are comprised primarily of equity and fixed income investments. Fluctuations in actual equity market returns and changes in interest rates may result in increased or decreased pension costs in future periods.

The following chart reflects the sensitivities associated with a change in certain actuarial assumptions:

Actuarial assumption	Change in assumption	Impact on accrued benefit obligation	Impact on pension cost reported in earnings
Discount rate	1%	$ 45.8	$ 2.6
Rate of return on plan assets	1%	$ –	$ 3.6

The discount rate used reflects high-quality fixed income securities currently available and expected to be available during the period to maturity of the pension benefits. We do not expect to make any changes to the rate in 2007.

The expected long-term rate of return on plan assets is based on past performance and economic forecasts for the types of investments held by the plan. For the year ended Dec. 31, 2006, the plan assets had a return of $35.4 million compared to a return of $43.9 million in 2005 and $33.4 million in 2004. The 2006 actuarial valuation used the same rate of return on plan assets (7.0 per cent) as was used in 2005 and 2004.

As a result of our plan asset return experience for our U.S. registered pension plan, at Dec. 31, 2005, the corporation was required under U.S. GAAP to recognize an additional minimum liability *(Note 30)*. The liability was recorded as a reduction in common equity through a charge to other comprehensive income (OCI), and did not affect net income for 2005.

The amount of the additional pension liability recognized for U.S. GAAP depended on a number of factors, including the discount rate and asset returns experienced, contributions made by the corporation and any resulting change in management's assumptions. Pension cost and cash funding requirements could increase in future years.

> NON-GAAP MEASURES

We evaluate our performance and the performance of our business segments using a variety of measures. Those discussed below are not defined under GAAP and therefore should not be considered in isolation or as an alternative to, or more meaningful than, net income or cash flow from operations as determined in accordance with GAAP as an indicator of our financial performance or liquidity. These measures are not necessarily comparable to a similarly titled measure of another company.

Each business unit assumes responsibility for its operating results measured to operating income. Operating income is a measure of financial performance used by our analysts and investors to analyze and compare companies on the basis of operating performance.

Operating income provides us with a measurement of operating performance that is readily comparable from period to period. For the period below, the writedown of coal inventory at Centralia in 2006 has been removed from the calculation as it distorts the comparability of operating income.

Gross margin less operating expenses and operating income are reconciled to net earnings below:

Year ended Dec. 31	2006	2005	2004
		(Restated, Note 1)	*(Restated, Note 1)*
Gross margin, excluding coal inventory writedown	**$ 1,535.8**	$ 1,442.0	$ 1,353.3
Operating expenses	**(1,012.9)**	(985.2)	(925.5)
	522.9	456.8	427.8
Mine closure charges, including inventory writedown	**(236.3)**	–	–
Asset impairment charges	**(130.0)**	(36.2)	–
Gain on sale of Meridian cogeneration facility	**–**	–	17.7
Gain on sale of TransAlta Power partnership units	**–**	–	44.8
Prior period regulatory decision	**–**	–	(22.9)
Operating income	**156.6**	420.6	467.4
Foreign exchange (loss) gain	**(0.5)**	1.3	0.7
Net interest expense	**(168.5)**	(188.6)	(207.4)
Equity loss	**(17.0)**	(0.9)	(8.5)
(Loss) earnings before non-controlling interests and income taxes	**(29.4)**	232.4	252.2
Non-controlling interests	**51.5**	18.5	46.0
(Loss) earnings before income taxes	**(80.9)**	213.9	206.2
Income tax (recovery) expense	**(125.8)**	39.6	46.6
Earnings from continuing operations	**44.9**	174.3	159.6
Earnings from discontinued operations, net of tax	**–**	12.0	9.6
Net earnings	**$ 44.9**	$ 186.3	$ 169.2

Presenting earnings on a comparable basis from period to period provides us with the ability to evaluate earnings trends more readily in comparison with prior periods' results. To do so, the following items which we believe would otherwise affect the comparability of our operating results from period to period, are excluded from net earnings: gains on sale of Sheerness, TA Power units, the Meridian Cogeneration Facility, mine closure charges, including inventory write-downs, and asset impairment charges, prior period regulatory decisions, and earnings from discontinued operations, net of tax.

Earnings presented on a comparable basis from period to period is reconciled to net earnings below:

Year ended Dec. 31	2006	2005	2004
		(Restated, Note 1)	*(Restated, Note 1)*
Earnings on a comparable basis	**$ 233.8**	$ 161.3	$ 127.1
Turbine impairment, net of tax	**(6.2)**	–	–
Change in tax rate related to prior periods	**55.3**	–	–
Centralia Gas impairment, net of tax	**(84.4)**	–	–
Centralia Coal writedown, net of tax	**(153.6)**	–	–
Prior period regulatory decision, net of tax	**–**	–	(14.9)
New Zealand tax settlement	**–**	–	6.8
Gain on sale of Meridian Cogeneration facility, net of tax	**–**	–	11.5
Gain on sale of TransAlta Power partnership units, net of tax	**–**	–	29.1
Earnings from discontinued operations, net of tax	**–**	12.0	9.6
Tax settlement on deferred receivable	**–**	13.0	–
Net earnings	**$ 44.9**	$ 186.3	$ 169.2
Weighted average common shares outstanding in the period	**200.8**	196.8	192.7
Earnings on a comparable basis per share	**$ 1.16**	$ 0.82	$ 0.66

Free cash flow is intended to demonstrate the amount of cash we have available to invest in capital growth initiatives, repay recourse debt or repurchase common shares.

The reconciliation between cash flow from operating activities and free cash flow is calculated below:

Year ended Dec. 31	2006	2005	2004
Cash flow from operating activities	**$ 489.6**	$ 619.8	$ 591.2
Add (Deduct):			
Sustaining capital expenditures	**(206.7)**	(286.5)	(203.7)
Dividends on common shares	**(121.0)**	(79.6)	(134.3)
Distribution to subsidiaries' non-controlling interest	**(74.4)**	(77.5)	(48.4)
Non-recourse debt repayments	**(51.3)**	(36.1)	(29.5)
Timing of contractually scheduled payments	**185.0**	–	–
Cash flows from equity investments	**(4.0)**	19.6	(5.2)
Free cash flow	**$ 217.2**	$ 159.7	$ 170.1

> SELECTED QUARTERLY FINANCIAL INFORMATION

2006 Quarters	**First**	**Second**	**Third**	**Fourth**
Revenue	**$ 733.7**	**$ 599.0**	**$ 684.0**	**$ 779.8**
Earnings (loss) from continuing operations	**69.2**	**86.4**	**35.3**	**(146.0)**
Net earnings (loss)	**69.2**	**86.4**	**35.3**	**(146.0)**
Basic earnings (loss) per common share:				
Continuing operations	**0.35**	**0.43**	**0.18**	**(0.72)**
Net earnings (loss)	**0.35**	**0.43**	**0.18**	**(0.72)**
Diluted earnings (loss) per common share:				
Continuing operations	**0.35**	**0.43**	**0.18**	**(0.72)**
Net earnings (loss)	**0.35**	**0.43**	**0.18**	**(0.72)**

2005 Quarters *(Restated, Note 1)*	First	Second	Third	Fourth
Revenue	$ 684.3	$ 621.2	$ 722.9	$ 810.1
Earnings from continuing operations	49.4	25.8	51.2	59.9
Net earnings	49.4	25.8	51.2	59.9
Basic earnings per common share:				
Continuing operations	0.25	0.13	0.26	0.24
Net earnings	0.25	0.13	0.26	0.30
Diluted earnings per common share:				
Continuing operations	0.25	0.13	0.26	0.24
Net earnings	0.25	0.13	0.26	0.30

Our results are partly seasonal due to the nature of the electricity market and related fuel costs. Higher maintenance costs are ordinarily incurred in the second and third quarters when electricity prices are expected to be lower, as electricity prices generally increase in the winter months in the Canadian market. Margins are also typically impacted in the second quarter due to the volume of hydro production resulting from spring runoff and rainfall in the Canadian and U.S. markets. Our results reflect the completion, acquisition and disposition of plants and facilities throughout 2004, 2005 and 2006 as described previously within this MD&A.

> CERTIFICATION

TransAlta's President & Chief Executive Officer and Executive Vice-President & Chief Financial Officer have filed with the Securities and Exchange Commission (SEC) certifications regarding the quality of TransAlta's public disclosures relating to its fiscal 2006 reports filed with the SEC.

As at Dec. 31, 2006, our Management, together with our President & Chief Executive Officer and Executive Vice-President & Chief Financial Officer has evaluated the effectiveness of the design and operation of our disclosure controls and procedures. Based upon this evaluation, our President & Chief Executive Officer and Executive Vice-President & Chief Financial Officer have concluded that our disclosure controls and procedures are effective.

There were no changes in our internal controls over financial reporting during the fiscal year that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

> FORWARD-LOOKING STATEMENTS

This MD&A contains forward-looking statements, including statements regarding the business and anticipated financial performance of TransAlta. In some cases, forward-looking statements can be identified by terms such as 'may', 'will', 'believe', 'expect', 'potential', 'enable', 'continue', or other comparable terminology. These statements are not guarantees of TransAlta's future performance and are subject to risks, uncertainties and other important factors that could cause the corporation's actual performance to be materially different from those projected. Some of the risks, uncertainties and factors include, but are not limited to: legislative and regulatory developments that could affect revenues, costs, and the speed and degree of competition entering the market; global capital markets activity; timing and extent of changes in commodity prices, prevailing interest rates, currency exchange rates, inflation levels and general economic conditions in geographic areas where TransAlta operates; results of financing efforts; changes in counterparty risk; and the impact of accounting policies issued by Canadian and U.S. standard setters. Given these uncertainties, the reader should not place undue reliance on these forward-looking statements. See additional discussion under Risk Factors and Risk Management in this MD&A.

TransAlta measures capacity as net maximum capacity (see glossary for definition of this and other key terms), which is consistent with industry standards. Capacity figures represent capacity owned and in operation unless otherwise stated.

MANAGEMENT'S REPORT

To the Shareholders of TransAlta Corporation

The Consolidated Financial Statements and other financial information included in this annual report have been prepared by management. It is management's responsibility to ensure that sound judgment, appropriate accounting principles and methods and reasonable estimates have been used in the preparation of this information. They also ensure that all information presented is consistent.

Management is also responsible for establishing and maintaining internal controls and procedures over the financial reporting process. The internal control system includes an internal audit function and an established business conduct policy that applies to all employees. In addition, the company has a code of conduct that applies to all employees and is signed annually. The code of conduct can be viewed on TransAlta's website (www.transalta.com). Management believes the system of internal controls, review procedures and established policies provides reasonable assurance as to the reliability and relevance of financial reports. Management also believes that TransAlta's operations are conducted in conformity with the law and with a high standard of business conduct.

Each year we document the design and operating effectiveness of internal control over external financial reporting. The results of this work have been subjected to an audit by the shareholders' auditors. As at year-end, we have reported that internal controls over financial reporting is effective. In compliance with Section 302 of the United States *Sarbanes-Oxley Act* of 2002, TransAlta's Chief Executive Officer and Chief Financial Officer will provide to the Securities and Exchange Commission a certification related to TransAlta's annual disclosure document in the U.S. (Form 40-F). The same certification will be provided to the Canadian Securities Administrators.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board carried out its responsibility principally through its Audit and Environment Committee. The Committee, which consists solely of independent directors, reviews the financial statements and annual report and recommends them to the Board for approval. The Committee meets with management, internal auditors and external auditors to discuss internal controls, auditing matters and financial reporting issues. Internal and external auditors have full and unrestricted access to the Audit and Environment Committee. The Committee also recommends the firm of external auditors to be appointed by the shareholders.

STEPHEN G. SNYDER
President & Chief Executive Officer
February 27, 2007

BRIAN BURDEN
Executive Vice-President & Chief Financial Officer

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

To the Shareholders of TransAlta Corporation

The following report is provided by management in respect of TransAlta Corporation's internal control over financial reporting (as defined in Rules 13a-15f and 15d-15f under the *United States Securities Exchange Act* of 1934).

TransAlta's management is responsible for establishing and maintaining adequate internal control over financial reporting for TransAlta.

Management has used the Committee of Sponsoring Organizations of the Treadway Commission (COSO) framework to evaluate the effectiveness of TransAlta Corporation's internal control over financial reporting. Management believes that the COSO framework is a suitable framework for its evaluation of TransAlta Corporation's internal control over financial reporting because it is free from bias, permits reasonably consistent qualitative and quantitative measurements of TransAlta Corporation's internal controls, is sufficiently complete so that those relevant factors that would alter a conclusion about the effectiveness of TransAlta Corporation's internal controls are not omitted and is relevant to an evaluation of internal control over financial reporting.

Internal control over financial reporting cannot provide absolute assurance of achieving financial reporting objectives because of its inherent limitations. Internal control over financial reporting is a process that involves human diligence and compliance and is subject to lapses in judgment and breakdowns resulting from human failures. Internal control over financial reporting also can be circumvented by collusion or improper overrides. Because of such limitations, there is a risk that material misstatements may not be prevented or detected on a timely basis by internal control over financial reporting. However, these inherent limitations are known features of the financial reporting process, and it is possible to design into the process safeguards to reduce, though not eliminate, this risk.

TransAlta Corporation's Consolidated Financial Statements include the accounts of the Sheerness, CE Generation and Genesee 3 joint ventures via proportionate consolidation in accordance with Canadian GAAP. Management does not have the contractual ability to assess the internal controls of these joint ventures but through commercial agreements, representation on boards of directors of these joint ventures and through our daily interactions, management is able to assess that key financial and commercial transactions are occurring properly. Once the financial information is obtained from the joint ventures it falls within the scope of TransAlta Corporation's internal controls framework. Management's conclusion regarding the effectiveness of internal controls does not extend to the internal controls at the transactional level of the joint ventures. The 2006 Consolidated Financial Statements of TransAlta Corporation included $1,749.5 million and $839.8 million of total and net assets, respectively, as of Dec. 31, 2006, and $498.7 million and $96.6 million of revenues and operational earnings, respectively, for the year then ended related to these joint ventures.

Management has assessed the effectiveness of TransAlta Corporation's internal control over financial reporting, as at Dec. 31, 2006, and has concluded that such internal control over financial reporting is effective. There are no material weaknesses in TransAlta Corporation's internal control over financial reporting that have been identified by management.

Ernst & Young LLP, who has audited the Consolidated Financial Statements of TransAlta Corporation for the year ended Dec. 31, 2006, has also issued a report on management's assessment of internal controls over financial reporting under Auditing Standard No. 2 of the Public Company Accounting Oversight Board (United States). This report is located on page 66 of this Annual Report.

STEPHEN G. SNYDER

President & Chief Executive Officer
February 27, 2007

BRIAN BURDEN

Executive Vice-President & Chief Financial Officer

INDEPENDENT AUDITORS' REPORT ON INTERNAL CONTROLS UNDER STANDARDS OF THE PUBLIC COMPANY ACCOUNTING OVERSIGHT BOARD (UNITED STATES)

To the Shareholders of TransAlta Corporation

We have audited management's assessment, included on page 65 of this annual report, that TransAlta Corporation maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). The Corporation's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Corporation's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records, that in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company' and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

As indicated in Management's Annual Report on Internal Control Over Financial Reporting, management's assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls of the CE Generation, Sheerness or Genesee 3 joint ventures, included in the Corporation's 2006 consolidated financial statements and constituting $1,749.5 million and $839.8 million of total and net assets, respectively, as at December 31, 2006, and $498.7 million and $96.6 million of revenues and net earnings, respectively, for the year then ended. Management did not assess the effectiveness of internal control over financial reporting at these joint ventures because the Corporation does not have the ability to dictate or modify the controls of the joint ventures, nor the ability, in practice, to assess those controls. Our audit of internal control over financial reporting of the Corporation did not include an evaluation of the internal controls over financial reporting of these joint ventures.

In our opinion, management's assessment that the Corporation maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on the COSO criteria. Also, in our opinion, the Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on the COSO criteria.

We have also audited, in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of TransAlta Corporation as at December 31, 2006 and 2005 and the consolidated statements of earnings and retained earnings and cash flows for each of the years in the three year period ended December 31, 2006, and our report dated February 27, 2007, expressed an unqualified opinion thereon.

Ernst & Young LLP

ERNST & YOUNG LLP
Chartered Accountants

Calgary, Canada
February 27, 2007

INDEPENDENT AUDITORS' REPORT ON FINANCIAL STATEMENTS

To the Shareholders of TransAlta Corporation

We have audited the consolidated balance sheets of TransAlta Corporation as at December 31, 2006 and 2005 and the consolidated statements of earnings and retained earnings and cash flows for each of the years in the three year period ended December 31, 2006. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosure in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe our audits provide a reasonable basis for our opinion.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2006 and 2005 and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2006 in conformity with Canadian generally accepted accounting principles.

As discussed in Note 1 (R) to the consolidated financial statements, in 2006 the Corporation changed its method of accounting for stripping costs incurred in the production of a mining operation, stock-based compensation for employees eligible to retire before the vesting period and defined benefit pension and other postretirement plans.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Corporation's internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 27, 2007 expressed an unqualified opinion thereon.

Ernst & Young LLP

ERNST & YOUNG LLP
Chartered Accountants

Calgary, Canada
February 27, 2007

CONSOLIDATED STATEMENTS OF EARNINGS AND RETAINED EARNINGS

Year ended Dec. 31	2006	2005	2004
(in millions of Canadian dollars except per share amounts)		*(Restated, Note 1)*	*(Restated, Note 1)*
Revenues	**$ 2,796.5**	$ 2,838.5	$ 2,586.2
Trading purchases	**(118.9)**	(174.1)	(197.7)
Fuel and purchased power *(Note 2)*	**(1,186.2)**	(1,222.4)	(1,035.2)
Gross margin	**1,491.4**	1,442.0	1,353.3
Operations, maintenance and administration	**581.3**	596.0	547.5
Depreciation and amortization	**410.3**	367.9	357.5
Taxes, other than income taxes	**21.3**	21.3	20.5
Operating expenses	**1,012.9**	985.2	925.5
Mine closure charges *(Note 2)*	**191.9**	–	–
Asset impairment charges *(Note 3)*	**130.0**	36.2	–
Gain on sale of Meridian Cogeneration facility *(Note 20)*	**–**	–	(17.7)
Gain on sale of TransAlta Power partnership units *(Note 20)*	**–**	–	(44.8)
Prior period regulatory decision *(Note 4)*	**–**	–	22.9
Operating income	**156.6**	420.6	467.4
Foreign exchange (loss) gain	**(0.5)**	1.3	0.7
Net interest expense *(Note 16)*	**(168.5)**	(188.6)	(207.4)
Equity loss	**(17.0)**	(0.9)	(8.5)
(Loss) earnings before non-controlling interests and income taxes	**(29.4)**	232.4	252.2
Non-controlling interests *(Notes 3 and 18)*	**51.5**	18.5	46.0
(Loss) earnings before income taxes	**(80.9)**	213.9	206.2
Income tax (recovery) expense *(Note 7)*	**(125.8)**	39.6	46.6
Earnings from continuing operations	**44.9**	174.3	159.6
Earnings from discontinued operations, net of tax *(Note 5)*	**–**	12.0	9.6
Net earnings	**44.9**	186.3	169.2
Common share dividends	**(201.0)**	(196.9)	(192.7)
Adjustment arising from normal course issuer bid *(Note 19)*	**–**	–	(1.1)
Retained earnings			
Opening balance	**866.1**	876.7	901.3
Closing balance	**$ 710.0**	$ 866.1	$ 876.7
Weighted average common shares outstanding in the period	**200.8**	196.8	192.7
Basic and diluted earnings per share *(Note 19)*			
Net earnings from continuing operations	**$ 0.22**	$ 0.88	$ 0.83
Earnings from discontinued operations	**–**	0.06	0.05
Net earnings	**$ 0.22**	$ 0.94	$ 0.88

See accompanying notes.

CONSOLIDATED BALANCE SHEETS

Dec. 31	2006	2005
(in millions of Canadian dollars)		*(Restated, Note 1)*
ASSETS		
Current assets		
Cash and cash equivalents	$ 65.6	$ 79.3
Accounts receivable *(Note 21)*	618.3	593.4
Prepaid expenses	9.1	9.8
Price risk management assets *(Note 6)*	61.0	63.8
Future income tax assets *(Note 7)*	25.8	26.6
Income taxes receivable	47.6	48.8
Inventory	53.0	23.1
Current portion of other assets *(Note 14)*	16.6	10.9
	897.0	855.7
Restricted cash *(Note 8)*	347.8	6.3
Investments *(Note 9)*	154.5	414.3
Long-term receivables *(Note 10)*	32.2	–
Property, plant and equipment *(Note 11)*		
Cost	8,588.0	8,572.9
Accumulated depreciation	(3,546.1)	(3,021.4)
	5,041.9	5,551.5
Assets held for sale, net *(Note 12)*	109.8	–
Goodwill	137.5	137.6
Intangible assets *(Note 13)*	292.1	343.7
Future income tax assets *(Note 7)*	294.0	170.1
Price risk management assets *(Note 6)*	21.9	13.8
Other assets *(Note 14)*	131.4	200.1
Total assets	$ 7,460.1	$ 7,693.1
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term debt *(Note 15)*	$ 361.9	$ 13.1
Accounts payable and accrued liabilities	441.9	590.3
Price risk management liabilities *(Note 6)*	30.3	58.3
Income taxes payable	22.3	13.8
Future income tax liabilities *(Note 7)*	19.9	18.2
Dividends payable	51.5	50.5
Deferred credits and other current liabilities *(Note 17)*	50.6	33.8
Current portion of long-term debt recourse *(Note 16)*	205.0	354.2
Current portion of long-term debt non-recourse *(Note 16)*	44.7	42.2
Preferred securities *(Note 16)*	175.0	–
	1,403.1	1,174.4
Long-term debt recourse *(Note 16)*	1,681.5	1,887.0
Long-term debt non-recourse *(Note 16)*	289.6	321.6
Preferred securities *(Note 16)*	–	175.0
Deferred credits and other long-term liabilities *(Note 17)*	423.4	332.1
Future income tax liabilities *(Note 7)*	698.6	738.8
Price risk management liabilities *(Note 6)*	1.0	8.6
Non-controlling interests *(Note 18)*	535.0	558.6
Common shareholders' equity		
Common shares *(Note 19)*	1,782.4	1,697.9
Retained earnings	710.0	866.1
Cumulative translation adjustment	(64.5)	(67.0)
	2,427.9	2,497.0
Total liabilities and shareholders' equity	$ 7,460.1	$ 7,693.1

Contingencies *(Notes 21 and 22)*
Commitments *(Notes 22 and 23)*

On behalf of the Board:

Donna Kaufman

DONNA SOBLE KAUFMAN
Director

William D. Anderson

WILLIAM D. ANDERSON
Director

See accompanying notes.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended Dec. 31	2006	2005	2004
(in millions of Canadian dollars)		*(Restated, Note 1)*	*(Restated, Note 1)*
Operating activities			
Net earnings	**$ 44.9**	$ 186.3	$ 169.2
Depreciation and amortization *(Note 24)*	**437.8**	400.9	390.1
Prior period regulatory decision *(Note 4)*	**–**	–	22.9
Non-controlling interests *(Notes 3 and 18)*	**51.5**	18.5	46.0
Asset retirement obligation accretion *(Note 17)*	**21.5**	19.3	19.3
Future income taxes *(Note 7)*	**(163.7)**	5.6	17.8
Asset retirement obligation costs settled *(Note 17)*	**(29.2)**	(29.4)	(19.7)
Unrealized (gains) losses from risk management activities	**(32.2)**	4.9	(9.7)
Foreign exchange loss (gain)	**0.5**	(1.3)	(0.7)
Mine closure charges *(Note 2)*	**191.9**	–	–
Asset impairment charges *(Note 3)*	**130.0**	36.2	–
Gain on sale of TransAlta Power partnership units *(Note 20)*	**–**	–	(44.8)
Gain on sale of assets	**–**	–	(24.7)
Equity loss	**17.0**	0.9	8.5
Other non-cash items	**8.8**	(3.0)	–
	678.8	638.9	574.2
Change in non-cash operating working capital balances	**(189.2)**	(19.1)	17.0
Cash flow from operating activities	**489.6**	619.8	591.2
Investing activities			
Additions to property, plant and equipment	**(223.7)**	(325.9)	(345.7)
Proceeds on sale of property, plant and equipment *(Note 12)*	**29.4**	1.6	43.2
Equity investment	**226.4**	(9.3)	(10.1)
Long-term receivables	**–**	–	90.8
Restricted cash *(Note 8)*	**(333.1)**	2.3	1.1
Proceeds on sale of TransAlta Power partnership units *(Note 20)*	**–**	–	116.5
Acquisitions *(Note 20)*	**(1.2)**	–	–
Realized foreign exchange gain on net investments *(Note 6)*	**53.9**	89.8	47.8
Proceeds on sale of long-term investments	**3.0**	–	–
Deferred charges and other	**(16.0)**	(1.0)	(1.0)
Cash flow used in investing activities	**(261.3)**	(242.5)	(57.4)
Financing activities			
Increase in (repayment of) short-term debt	**348.1**	(23.6)	(85.4)
Repayment of long-term debt	**(396.7)**	(139.3)	(284.7)
Dividends on common shares	**(133.9)**	(99.2)	(135.4)
Issuance of long-term debt	**–**	200.0	2.7
Redemption of preferred securities	**–**	(300.0)	–
Net proceeds on issuance of common shares	**12.9**	19.6	1.1
Distributions to subsidiaries' non-controlling interests	**(74.4)**	(77.5)	(48.4)
Deferred financing charges and other	**–**	–	(1.2)
Reduction in advance to TransAlta Power *(Note 20)*	**0.8**	23.7	2.0
Cash flow used in financing activities	**(243.2)**	(396.3)	(549.3)
Cash flow used in operating, investing and financing activities	**(14.9)**	(19.0)	(15.5)
Effect of translation on foreign currency cash	**1.2**	(2.9)	(7.1)
(Decrease) in cash and cash equivalents	**(13.7)**	(21.9)	(22.6)
Cash and cash equivalents, beginning of period	**79.3**	101.2	123.8
Cash and cash equivalents, end of period	**$ 65.6**	$ 79.3	$ 101.2
Cash taxes paid	**$ 35.6**	$ 14.7	$ 4.6
Cash interest paid	**$ 181.2**	$ 183.7	$ 218.2

See accompanying notes.

(Tabular amounts in millions of Canadian dollars, except as otherwise noted)

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A. Consolidation

These consolidated financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles (Canadian GAAP). These accounting principles are different in some respects from United States generally accepted accounting principles (U.S. GAAP). The significant differences are described in *Note 30.*

The consolidated financial statements include the accounts of TransAlta Corporation (TransAlta or the corporation), all subsidiaries and the proportionate share of the accounts of joint ventures and jointly controlled corporations.

B. Use of Estimates

The preparation of financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the period. Actual results could differ from those estimates due to factors such as fluctuations in interest rates, currency exchange rates, inflation levels and commodity prices, changes in economic conditions and legislative and regulatory changes *(Notes 6, 13, 22 and 26)*.

C. Revenue Recognition

The majority of the corporation's revenues are derived from the sale of physical power and from energy marketing and trading activities. Revenues under long-term electricity and thermal sales contracts generally include one or more of the following components: fixed capacity payments for being available, energy payments for generation of electricity, incentives or penalties for exceeding or not meeting availability targets, excess energy payments for power generation above committed capacity and ancillary services. Each is recognized upon output, delivery, or satisfaction of specific targets, all as specified by contractual terms. Revenues from non-contracted capacity are comprised of energy payments for each megawatt hour (MWh) produced at market prices and are recognized upon delivery.

Derivatives used in trading activities include physical and financial swaps, forward sales contracts, futures contracts and options, which are used to earn trading revenues and to gain market information. These derivatives are accounted for using the fair value method of accounting. Derivatives, other than real-time physical contracts, are presented on a net basis in the statements of earnings. Real-time physical contracts meet the definition of derivative contracts held for delivery and therefore realized gains and losses are reported gross in the consolidated statements of earnings. The initial recognition of fair value and subsequent changes in fair value affect reported earnings in the period the change occurs. The fair values of those instruments that remain open at the balance sheet date represent unrealized gains or losses and are presented on the balance sheets as price risk management assets and liabilities. Non-derivative trading contracts are accounted for using the accrual method.

The majority of the corporation's derivatives have quoted market prices on active exchanges or over-the-counter quotes are available from brokers. However, some derivatives are not traded on an active exchange or the contracts extend beyond the time period for which market-based quotes are available, requiring the use of internal valuation techniques or models (mark-to-model accounting).

D. Discontinued Operations

The results of discontinued operations are presented net of tax on a one-line basis in the consolidated statements of earnings. Interest expense, direct corporate overheads and income taxes are allocated to discontinued operations. General corporate overheads are not allocated to discontinued operations.

E. Inventory

The corporation's inventory balance represents fuel which is valued at the lower of cost and market value, defined as net replacement value. Inventory cost is determined using moving average cost. The costing method used is direct costing, which is determined as the sum of all applicable expenditures and charges directly or indirectly incurred in bringing an inventory item to its existing condition and location.

F. Property, Plant and Equipment

The corporation's investment in property, plant and equipment (PP&E) is stated at original cost at the time of construction, purchase or acquisition. Original cost includes items such as materials, labour, interest and other appropriately allocated costs. As costs are expended for new construction, the entire amount is capitalized as PP&E on the consolidated balance sheet and is subject to depreciation upon commencement of commercial operations. The cost of routine maintenance and repairs, such as inspections and corrosion removal, and the replacement of minor parts, are charged to expense as incurred. Certain expenditures relating to replacement of components incurred during major maintenance are capitalized and amortized over the estimated benefit period of such expenditures. A

component is a tangible portion of the asset that can be separately identified as an asset and depreciated over its own expected useful life, and is expected to provide a benefit of greater than one year.

The estimate of the useful life of PP&E is based on current facts and past experience, and takes into consideration existing long-term sales agreements and contracts, current and forecasted demand, and the potential for technological obsolescence. The useful life is used to estimate the rate at which the PP&E is depreciated or amortized. These estimates are subject to revision in future periods based on new or additional information. Depreciation and amortization are calculated using straight-line and unit of production methods. Coal rights are amortized on a unit of production basis, based on the estimated mine reserves.

TransAlta capitalizes interest on capital invested in projects under construction. Upon commencement of commercial operations, capitalized interest, as a portion of the total cost of the plant, is amortized over the estimated useful life of the plant.

On an annual basis, and when indicators of impairment exist, TransAlta determines whether the net carrying amount of PP&E is recoverable from future undiscounted cash flows. Factors that could indicate an impairment exists include significant underperformance relative to historical or projected future operating results, significant changes in the manner or use of the assets, significant negative industry or economic trends, or a change in the strategy for the corporation's overall business. In some cases, these events are clear. However, in many cases, a clearly identifiable event indicating possible impairment does not occur. Instead, a series of individually insignificant events occur over a period of time leading to an indication that an asset may be impaired. This can be further complicated where TransAlta is not the operator of the facility. Events can occur in these situations that may not be known until a date subsequent to their occurrence.

The corporation's businesses, the markets and business environment are continually monitored, and judgments and assessments are made to determine whether an event has occurred that indicates possible impairment. If such an event has occurred, an estimate is made of future undiscounted cash flows from the PP&E. If the total of the undiscounted future cash flows, excluding financing charges with the exception of plants that have specifically dedicated debt, is less than the carrying amount of the PP&E, an asset impairment must be recognized in the financial statements. The amount of the impairment charge to be recognized is calculated by subtracting the fair value of the asset from the carrying value of the asset. Fair value is the amount at which an item could be bought or sold in a current transaction between willing parties, and is normally estimated by calculating the present value of expected future cash flows related to the asset.

During the annual review of the generating assets, changes in the outlook for dispatch rates and trading values and their impact on plant profitability resulted in a $130 million pre-tax impairment charge to write the Centralia Gas plant down to its fair value *(Note 3)*.

On Nov. 27, 2006, TransAlta stopped mining at the Centralia Coal mine as a result of increased costs and unfavourable geological events. All associated mining and reclamation equipment was written down to the lower of net book value or anticipated realized proceeds *(Note 2)*.

G. Goodwill

Goodwill is the cost of an acquisition less the fair value of the net assets of an acquired business. Goodwill and certain intangibles are not subject to amortization, but are instead tested for impairment at least annually, or more frequently if an analysis of events and circumstances indicate that a possible impairment may arise earlier. These events could include a significant change in financial position of the reporting unit to which the goodwill relates or significant negative industry or economic trends. To test for impairment, the fair value of the reporting units to which the goodwill relates is compared to the carrying values of the reporting units. The corporation determined that the fair values of the reporting units, based on historical cash flows and estimates of future cash flows, exceeded their carrying values. There was no impairment of goodwill at Dec. 31, 2006 or 2005.

H. Intangible Assets

Intangible assets consist of power sale contracts, with rates higher than market rates at the date of acquisition, acquired in the purchase of CE Generation LLC (CE Gen), a jointly controlled enterprise *(Note 27)*. Sale contracts are valued at cost and are amortized on a straight-line basis over the remaining contract period, which ranges from three to 28 years at the date of acquisition.

I. Asset Retirement Obligations (ARO)

The corporation recognizes ARO in the period in which they are incurred if a reasonable estimate of a fair value can be determined. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset. The liability is accrued over the estimated time period until settlement of the obligation and the asset is depreciated over the estimated useful life of the asset. Reclamation costs for mining assets are recognized on a unit of production basis.

TransAlta recorded an ARO for all generating facilities for which it is legally required to remove the facilities at the end of their useful lives and restore the plant and mine sites to their original condition. For some hydro facilities, the corporation is required to remove the generating equipment, but is not legally required to remove the structures. TransAlta has recognized legal obligations arising from government legislation, written agreements between entities and case law. The asset retirement liabilities are recognized when the ARO is incurred. Asset retirement liabilities for coal mines are incurred over time, as new areas are mined, and a portion of the liability is settled over time as areas are reclaimed prior to final pit reclamation.

J. Investments

Effective Jan. 1, 2005, TransAlta retroactively adopted the new CICA Accounting Guideline 15 "Consolidation of Variable Interest Entities" (VIE). The wholly owned subsidiaries that hold TransAlta's interests in the Campeche and Chihuahua power plants are considered VIEs and are shown as equity investments.

Investments in shares of companies over which the corporation exercises significant influence are accounted for using the equity method. Other investments are carried at cost. If there is other than a temporary decline in the value of an investment, it is written down to net realizable value.

K. Other Assets

Deferred license fees and deferred contract costs are amortized on a straight-line basis over the useful life of the related assets or long-term contracts.

Financing costs for the issuance of long-term debt and preferred securities are amortized to earnings on a straight-line basis over the term of the related issue.

Other costs capitalized on the balance sheet include project development costs, which include external, direct and incremental costs that are necessary for completion of a potential acquisition or construction project. Such costs are included in operating expenses until construction of a plant or acquisition of an investment is likely to occur, there is reason to believe that future costs are recoverable and that efforts will result in future value to the corporation, at which time the future costs are included in PP&E or investments. The appropriateness of the carrying value of these costs is evaluated each reporting period, and unrecoverable amounts of capitalized costs for projects no longer probable of occurring are charged to expense in the current period.

L. Income Taxes

The corporation uses the liability method of accounting for income taxes for its operations. Under the liability method, income taxes are recognized for the differences between financial statement carrying values and the respective income tax basis of assets and liabilities (temporary differences), and the carry forward of unused tax losses. Future income tax assets and liabilities are measured using income tax rates expected to apply in the years in which temporary differences are expected to be recovered or settled. The effect on future income tax assets and liabilities of a change in tax rates is included in earnings in the period the change is substantively enacted. Future income tax assets are evaluated annually and if realization is not considered 'more likely than not', a valuation allowance is provided.

M. Employee Future Benefits

The corporation accrues its obligations under employee benefit plans and the related costs, net of plan assets. The cost of pensions and other post-employment and post-retirement benefits earned by employees is actuarially determined using the projected benefit method pro-rated on services and management's best estimate of expected plan investment performance, salary escalation, retirement ages of employees and expected health care costs. The defined benefit pension plans are based on an employee's final average earnings and years of service. Pension benefits will increase annually by two per cent. The expected return on plan assets is based on the historical returns earned by assets of similar risk and performance. The discount rate used to calculate the interest cost on the accrued benefit obligation is determined by reference to market interest rates at the balance sheet date on high-quality debt instruments with cash flows that match the timing and amount of expected benefit payments. Past service costs from plan amendments are amortized on a straight-line basis over the estimated average remaining service period of employees active at the date of amendment (EARSL). The excess of the net cumulative unamortized actuarial gain or loss over 10 per cent of the greater of the accrued benefit obligation and the market value of plan assets is amortized over the estimated average remaining service period of the active employees. When the restructuring of a benefit plan gives rise to both a curtailment and settlement of obligations, the curtailment is accounted for prior to the settlement. Transition obligations and assets arising from the prospective adoption of new accounting standards are amortized over EARSL.

N. Foreign Currency Translation

The corporation's self-sustaining foreign operations are translated using the current rate method. Translation gains and losses are deferred and included in the cumulative translation adjustment (CTA) account in shareholders' equity. Foreign currency denominated monetary and non-monetary assets and liabilities are translated at exchange rates in effect on the balance sheet date.

Transactions denominated in foreign currencies are translated at the exchange rate on the transaction date. The resulting exchange gains and losses on these items are included in net earnings.

O. Derivatives and Financial Instruments

Derivatives used in trading activities are described in *Note 1(C)*.

Physical and financial swaps, forward sales contracts, futures contracts and options are used to hedge the corporation's exposure to fluctuations in electricity and natural gas prices related to output from the plants. Under Canadian GAAP, if hedging criteria are met (described below), gains and losses on these derivatives are recognized in earnings in the same period and financial statement caption as the hedged exposure (settlement accounting). The derivatives are not recorded on the balance sheet.

Cross-currency interest rate swaps, foreign currency forward contracts and foreign currency debts are used to hedge exposure to changes in the carrying values of the corporation's net investments in foreign operations as a result of changes in foreign exchange rates. Under Canadian GAAP, gains and losses on the principal component of the cross-currency interest rate swaps as well as gains and losses on the forward sales contracts and foreign currency long-term debt are deferred and included in CTA. The gains and losses on the principal component of the cross-currency interest rate swaps as well as the gains and losses on forward sales contracts are deferred and recorded in other assets *(Note 14)* or deferred credits and other long-term liabilities *(Note 17)* as appropriate.

Foreign currency forward contracts are used to hedge the foreign exchange exposures resulting from anticipated contracts and firm commitments denominated in foreign currencies. Under Canadian GAAP, if hedge criteria are met, these derivatives are not recognized on the balance sheet. Upon settlement of the derivative, any gain or loss on the forward contracts is deferred and included in other assets *(Note 14)* or deferred credits and other long-term liabilities *(Note 17)*, and is included in the cost of the asset or liability when the asset is purchased and depreciated over the asset's estimated useful life (settlement accounting).

Interest rate swaps are used to manage the impact of fluctuating interest rates on existing debt. These instruments are not recognized on the balance sheet under Canadian GAAP. Interest rate swaps require the periodic exchange of payments without the exchange of the notional

principal amount on which the payments are based. If hedge criteria are met, interest expense on the debt is adjusted to include the payments made or received under the interest rate swaps (settlement accounting).

To be accounted for as a hedge under both Canadian and U.S. GAAP, a derivative must be designated and documented as a hedge, and must be effective at inception and on an ongoing basis. The documentation defines all relationships between hedging instruments and hedged items, as well as the corporation's risk management objective and strategy for undertaking various hedge transactions. The process includes linking derivatives to specific assets and liabilities on the balance sheet or to specific firm commitments or anticipated transactions. The corporation also formally assesses, both at the hedge's inception and on an ongoing basis, whether the derivatives used are highly effective in offsetting changes in fair values or cash flows of hedged items. Hedge effectiveness of cash flows is achieved if the derivatives' cash flows substantially offset the cash flows of the hedged item and the timing of the cash flows is similar. Hedge effectiveness of fair values is achieved if changes in the fair value of the derivative substantially offset changes in the fair value of the item hedged. If a hedge is determined to be ineffective, U.S. and Canadian GAAP require the ineffective portion to be recognized in earnings in the current period. If the above hedge criteria are not met, the derivative is accounted for on the balance sheet at fair value, with the initial fair value and subsequent changes in fair value recorded in earnings in the period of change.

If a derivative that has been accorded hedge accounting matures, expires, is sold, terminated or cancelled, and is not replaced as part of the corporation's hedging strategy, the termination gain or loss is deferred and recognized when the gain or loss on the item hedged is recognized. If a designated hedged item matures, expires, is sold, extinguished or terminated, or the hedged item is no longer probable of occurring, any previously deferred amounts associated with the hedging item are recognized in current earnings along with the corresponding gains or losses recognized on the hedged item. If a hedging relationship is terminated or ceases to be effective, hedge accounting is not applied to subsequent gains or losses. Any previously deferred amounts are carried forward and recognized in earnings in the same period as the hedged item.

P. Stock-Based Compensation Plans

The corporation has three types of stock-based compensation plans comprised of two stock option-based plans, and a Performance Share Ownership Plan (PSOP), described in *Note 25*. Under the fair value method, compensation expense is measured at the grant date at fair value and recognized over the service period. Effective Jan. 1, 2003, the corporation elected to prospectively use the fair value method of accounting for stock-based compensation arrangements. In 2006, the corporation did not grant options to its employees. *Note 25* provides pro forma measures of net earnings and earnings per share had compensation expense been recognized for awards granted prior to 2003 based on the estimated fair value of the options on the grant date in accordance with the fair value method of accounting for stock-based compensation.

Stock grants under PSOP are accrued in corporate operations, maintenance and administration (OM&A) expense as earned to the balance sheet date, based upon the percentile ranking of the total shareholder return of the corporation's common shares in comparison to the total shareholder returns of companies comprising the S&P/TSX Composite Index. Compensation expense under the phantom stock option plan is recognized in OM&A expense for the amount by which the quoted market price of TransAlta's shares exceeds the option price, and adjusted for changes in each period for changes in the excess over the option price. If stock options or stock are repurchased from employees, the excess of the consideration paid over the carrying amount of the stock option or stock cancelled is charged to retained earnings.

Q. Cash and Cash Equivalents

Cash and cash equivalents are comprised of cash and highly liquid investments with original maturities of three months or less.

R. Accounting Changes

Effective Jan. 1, 2006, TransAlta early adopted the Canadian Institute of Chartered Accountants' (CICA) *Emerging Issues Committee Abstract* 160 (EIC-160) *Stripping Costs Incurred in the Production of a Mining Operation*. Under EIC-160, stripping costs to remove overburden and waste materials to access mineral deposits should be accounted for as variable production costs during the period that the stripping costs are incurred. Previously, a portion of the stripping costs would have been carried forward to future periods as part of inventory or prepaid expenses.

The corporation has considered costs incurred during 2005 and previous years, which meet the definition of stripping costs under EIC-160. Factors considered in the analysis include stripping costs, tons of coal produced and whether the stripping costs could be capitalized.

As a result of this review, the corporation determined that costs incurred during 2005 and previous years did meet the definition of stripping costs under EIC-160 and therefore stripping costs have been accounted for as period costs. Prior periods have been restated to reflect this change in accounting policy. The impact on the balance sheet and income statements are as follows:

	As previously disclosed	Change	As restated
2005 Prepaid expenses	$ 75.8	$ (66.0)	$ 9.8
2005 Inventory	27.7	(4.6)	23.1
2005 Net earnings	198.8	(12.5)	186.3
2004 Prepaid expenses	52.3	(47.1)	5.2
2004 Inventory	39.9	(3.3)	36.6
2004 Net earnings	170.2	(1.0)	169.2

During the first quarter of 2006, there was a change in the amortization period of the Ottawa, Mississauga, Windsor-Essex, Fort Saskatchewan and Meridian plants. Previously, these plants were being amortized using the units of production method over the life of the plants. After reviewing the estimated useful life and considering the uncertainty for the plants' operations beyond the terms of the current sales contracts, TransAlta determined that it was more reasonable to allocate the remaining net book value of the plants on a straight-line basis over the remaining term of the respective contracts. For the year ended Dec. 31, 2006, the amortization related to the Ottawa, Mississauga, Windsor-Essex, Fort Saskatchewan and Meridian plants is $13.4 million higher than the same period in 2005.

In January 2005, the CICA issued four new accounting standards that are effective for interim and annual financial statements relating to fiscal years beginning on or after Oct. 1, 2006. These new standards include Section 1530, Comprehensive Income, Section 3251, Equity, Section 3855, Financial Instruments – Recognition and Measurement and Section 3865, Hedges. The corporation adopted these standards as of Jan. 1, 2007. These standards are expected to have a minimal impact on the presentation of the financial statements.

Stock-Based Compensation for Employees Eligible to Retire Before the Vesting Period

In July 2006, the Emerging Issues Committee issued EIC-162, *Stock-Based Compensation for Employees Eligible to Retire Before the Vesting Date* (EIC-162). This abstract accelerates the recognition of compensation costs for stock-based awards based on the retirement eligibility of the employee at the grant date and during the vesting period. EIC-162 is effective for interim and annual periods ending on or after Dec. 31, 2006 and should be applied retroactively. TransAlta adopted this standard effective in the fourth quarter of 2006. Comparative balances have not been restated as the impact on prior periods is not significant.

Issue 06-2 – Accounting for Sabbatical Leave and Other Similar Benefits Pursuant to FASB Statement No. 43, Accounting for Compensated Absences

In June 2006, the Emerging Issues Task Force (EITF) issued *EITF Issue No. 06-2 Accounting for Sabbatical Leave and Other Similar Benefits Pursuant to FASB Statement No. 43, Accounting for Compensated Absences* (Issue No. 06-2). Under Issue No. 06-2 a company should accrue for sabbatical leave or other similar benefits if (i) the employee is required to complete a minimum service period to be entitled to the benefit, (ii) there is no increase to the benefit if the employee provides additional years of service, (iii) the employee continues to be a compensated employee during his or her absence, and (iv) the employer does not require the employee to perform any duties during his or her absence. Issue No. 06-2 is effective for fiscal years beginning after Dec. 15, 2006. TransAlta has evaluated the accounting guidance and has adopted the consensus effective Jan. 1, 2007. Comparative balances have not been restated as the impact on prior periods is not significant.

Employers' Accounting for Defined Benefit Pension and Other Post-retirement Plans

In September 2006, the FASB issued *Statement of Financial Accounting Standards* (SFAS) No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans – an Amendment of FASB Statements No. 87, 88, 106, and 132(R)* (SFAS 158). SFAS 158 requires companies to report the funded status of their defined benefit pension plans on the balance sheet with changes in the funded status recognized in other comprehensive income in the year of the change. SFAS 158 also requires additional disclosure. SFAS 158 is effective for years ending after Dec. 15, 2006. TransAlta has adopted the requirements of SFAS 158 and the results have been reflected in the U.S. GAAP reconciliation *(Note 30)*.

2. MINE CLOSURE CHARGES

On Nov. 27, 2006, TransAlta stopped mining at the Centralia Coal mine as a result of increased costs and unfavourable geological conditions. All associated mining and reclamation equipment was written down to the lower of net book value or anticipated realized proceeds. Mine infrastructure, including coal processing equipment and structures, haul roads and other equipment were written down to anticipated net salvage value. Asset retirement costs, representing the unamortized cost of future reclamation, was also written off. In addition, employee termination costs and other miscellaneous expenses were recorded. The total of these writedowns and provisions was $191.9 million.

As a result of the closure, all internally produced coal was also written down to fair market value, which is replacement cost, resulting in an expense of $44.4 million being recorded in fuel and purchased power. The total amounts are summarized in the table below:

Writedown of coal inventory	$	44.4
Impact on gross margin		(44.4)
Mine closure charges		
Mine equipment and infrastructure writedown		72.1
ARO writedown		81.3
Severance costs and other		38.5
Total mine closure charges		191.9
Loss before income taxes	$	(236.3)
Income tax recovery		82.7
Net loss impact of event	$	(153.6)

3. ASSET IMPAIRMENT CHARGES

During the annual review of its generating assets, changes in the outlook for dispatch rates and trading values and their impact on plant profitability resulted in the determination that the full book value of the Centralia Gas facility was unlikely to be recovered from future cash flows. As a result of a market valuation, TransAlta recorded a $130 million pre-tax impairment charge to write this plant down to its fair value. This asset is included in the Generation segment.

For the year ended Dec. 31, 2005, TA Cogen, a subsidiary that is owned 50.01 per cent by TransAlta and 49.99 per cent by TA Power, a publicly traded entity, recorded an impairment charge of $78.3 million in respect of the Ottawa facility as the net book value of that facility exceeded its net recoverable amount, measured as the future cash flows from the facility. The net book value of the Ottawa facility in the accounts of the corporation is lower than that in TA Cogen. The carrying value in TransAlta is fully recoverable from future cash flows of the facility. The difference in net book value between the accounts of the corporation and TA Cogen is due to the higher purchase price of the plant by TA Cogen. The corporation has recognized an increase in depreciation expense of $36.2 million related to TA Power's share of the impairment charge. This amount is offset by a recovery in the earnings attributable to non-controlling interests in the corporation's income statement.

4. PRIOR PERIOD REGULATORY DECISION

In response to a complaint filed by San Diego Gas & Electric Company under Section 206 of the *Federal Power Act* (FPA), Federal Energy Regulatory Commission (FERC) established a claim of approximately US$46 million in refunds owing by TransAlta for sales made by it in the organized markets of the California Power Exchange (PX) and the California Independent System Operator (ISO) during the Oct. 2, 2000 through June 20, 2001 period (the Main Refund Transactions). TransAlta has provided US$46 million to account for refund liabilities relating to Main Refund Transactions.

TransAlta filed a cost of service based petition for relief from these refund obligations. FERC rejected TransAlta's relief petition. On Dec. 1, 2006 TransAlta filed for a rehearing of FERC's rejection. FERC has not yet issued a decision on rehearing.

During settlement negotiations, the complaintants have sought to obtain refunds for two sets of transactions beyond the Main Refund Transactions. The first set includes sales made by sellers in the PX and ISO markets in the period May 1 to Oct. 1, 2001 (The Summer Transactions). The other set includes bilateral transactions between all sellers and a component of the California Department of Water Resources (CDWR) referred to as CERS (The CERS Transactions). FERC has specifically rejected attempts to introduce refunds for the Summer and CERS transactions. Nonetheless, the California parties have sought rehearing of FERC's refusal and appealed the refusal to the U.S. Court of Appeals for the Ninth Circuit. TransAlta does not presently believe the California parties will be successful in obtaining refunds alleged for the Summer and CERS transactions. TransAlta has not made any provision for such alleged refunds at this time.

5. DISCONTINUED OPERATIONS

A. Transmission

In June 2004, a settlement was reached to finalize the sale of the corporation's Transmission operations. In April 2002, the Transmission operations were sold for proceeds of $820.7 million. The disposal resulted in an after-tax gain on sale of $120.0 million that was recorded in 2002. During 2004, final working capital adjustments were made to reflect post-closing adjustments and other provisions related to closing costs, which resulted in an additional $9.6 million after-tax gain.

B. Alberta Distribution and Retail (D&R)

In August 2000, the corporation sold its Alberta D&R business for proceeds of $857.3 million. The original gain recorded on this transaction was $262.4 million. During the fourth quarter of 2005, the corporation settled an outstanding income tax dispute related to this business. Included in earnings from discontinued operations for the year ended Dec. 31, 2005 is $12.0 million related to this matter. The settlement of this issue brings the final gain on disposal of the Alberta D&R business to $274.4 million.

6. PRICE RISK MANAGEMENT ASSETS AND LIABILITIES

A. Foreign Exchange Rate Risk Management

I. Hedges of Foreign Operations

The corporation has exposure to changes in the carrying values of its self-sustaining foreign operations as a result of changes in foreign exchange rates. The corporation uses cross-currency interest rate swaps at fixed and floating rate terms, forward sales contracts, and direct foreign currency debt to hedge these exposures. The principal component of the cross-currency interest rate swaps and direct foreign currency debt hedge a portion of the carrying value of foreign operations. Translation gains and losses related to these components are deferred and included in CTA in shareholders' equity on a net of tax basis.

Realized gains and losses arising from the hedging of net investments and inter-company transactions are reflected as an investing activity in the statement of cash flows. Upon the settlement of certain financial instruments designated as net investment hedges, a foreign exchange gain of $53.9 million was realized in 2006 (2005 – $89.8 million; 2004 – $47.8 million). This is recorded in the corporation's cumulative translation account in total equity.

Details of the notional amounts of cross-currency interest rate swaps are as follows:

As at Dec. 31	2006			2005		
	Amount	**Fair value**	**Maturities**	Amount	Fair value	Maturities
Australian dollars	**AUD$34.0**	**$ (0.6)**	**2009**	AUD$34.0	$ 0.8	2009
U.S. dollars	**US$528.2**	**$ 41.1**	**2007-2014**	US$752.1	$ 101.9	2007-2015

In addition, the corporation has designated U.S. dollar denominated long-term debt *(Note 16)* in the amount of US$600.0 million (2005 – US$600.0 million) as a hedge of its net investment in U.S. denominated companies with $173.6 million of related foreign currency losses (2005 – $177.0 million loss) deferred and included in CTA.

The corporation has also hedged a portion of its net investment in self-sustaining subsidiaries with foreign currency forward sales contracts as shown below:

As at Dec. 31	2006			2005		
	Amount	**Fair value**	**Maturities**	Amount	Fair value	Maturities
U.S. dollars	**US$472.5**	**$ 9.9**	**2007-2008**	US$339.9	$ 15.8	2006-2008
Australian dollars	**AUD$48.8**	**$ (0.2)**	**2007**	AUD$22.8	$ (0.1)	2006
Mexican pesos	**MXN–**	**$ –**	**–**	MXN 871.6	$ (11.9)	2009

In addition, the corporation has hedged foreign currency denominated inter-company loans to self-sustaining foreign subsidiaries using forward contracts with a notional amount of US$37.1 million (2005 – US$49.2 million) and a net fair value liability of $2.3 million (2005 – $0.7 million).

At Dec. 31, 2006, a $54.0 million asset (2005 – $101.9 million) and a $16.8 million liability (2005 – $14.7 million) related to the cross-currency interest rate swaps and forward sales contracts were recorded in other assets *(Note 14)* and deferred credits and other long-term liabilities *(Note 17)*, respectively.

II. Hedges of Future Foreign Currency Obligations

The corporation has hedged future foreign currency obligations through forward purchase contracts as follows:

As at Dec. 31	2006					2005			
Currency sold	**Amount sold**	**Currency purchased**	**Amount purchased**	**Fair value asset (liability)**	**Maturities**	Amount sold	Amount purchased	Fair value asset (liability)	Maturities
Canadian dollars	**$32.9**	**US$**	**US$28.8**	**$ 0.31**	**2007**	$ –	US$6.6	$ (0.2)	2006
U.S. dollars	**$2.1**	**Cdn$**	**$2.3**	**$ –**	**2007**	71.4	$83.0	$ 0.4	2006
Mexican pesos	**–**	**US$**	**–**	**$ –**	**N/A**	MXN160.75	US$15.1	$ 0.1	2006
Canadian dollars	**$36.9**	**Euro**	**EUR24.2**	**$ (0.2)**	**2007-2008**	$ –	EUR$–	$ –	N/A

At Dec. 31, 2006, a $0.5 million asset (2005 – $0.7 million) and a $0.3 million liability (2005 – $0.2 million) related to these hedges was recorded in other assets *(Note 14)* and deferred credits and other long-term liabilities *(Note 17)*, respectively.

B. Interest Rate Risk Management

I. Existing Debt

The corporation has converted fixed interest rate debt with rates ranging from 5.75 per cent to 6.90 per cent to floating rates through receive fixed pay floating interest rate swaps *(Note 14)* as shown below:

As at Dec. 31	2006			2005		
	Notional amount	**Fair value of swaps**	**Maturities**	Notional amount	Fair value of swaps	Maturities
Fixed rate debt	**$200.0**	**$ 15.2**	**2011**	$375.0	$ 30.8	2006-2011
	US$300.0	**$ (9.7)**	**2013**	US$300.0	$ (4.8)	2013

The corporation has a forward start pay fixed swap outstanding at fixed rates ranging from 4.39 per cent to 4.50 per cent. In 2005, the corporation had converted debt at floating interest rates to a fixed rate of 7.2 per cent through a receive floating rate pay fixed interest rate swaps *(Note 6)*, as shown below:

As at Dec. 31	2006			2005		
	Notional amount	**Fair value of swaps**	**Maturity**	Notional amount	Fair value of swaps	Maturity
Floating rate debt	**125**	**$ 0.2**	**2017**	US$37.1	$ (1.3)	2008

Including the interest rate swaps above, 28.4 per cent of the corporation's debt is subject to floating interest rates (2005 – 24.8 per cent).

The fair value of the corporation's fixed interest long-term debt changes as interest rates change, with details as follows:

As at Dec. 31	2006		2005	
	Carrying amount	**Fair value**	Carrying amount	Fair value
Long-term debt, including current portion	**$ 2,395.8**	**$ 2,505.4**	$ 2,780.0	$ 2,905.0

At Dec. 31, 2006, a $25.8 million asset (2005 – $38.4 million) related to the interest rate swaps was recorded in other assets *(Note 14)*.

C. Energy Commodities Price Risk Management

I. Trading Activities

The corporation markets energy derivatives, including physical and financial swaps, forwards and options, to optimize returns from assets, to earn trading revenues and to gain market information.

At Dec. 31, 2006 and 2005, details of the corporation's fixed price trading positions were as follows:

	Electricity	Natural gas
Units (thousands)	(MWh)	(GJ)
Fixed price payor, notional amounts, Dec. 31, 2006	**13,944**	**20,289**
Fixed price payor, notional amounts, Dec. 31, 2005	19,315	11,126
Fixed price receiver, notional amounts, Dec. 31, 2006	**21,536**	**26,231**
Fixed price receiver, notional amounts, Dec. 31, 2005	19,047	12,158
Maximum term in months, Dec. 31, 2006	**33**	**16**
Maximum term in months, Dec. 31, 2005	24	12

The carrying and fair value of energy commodity trading assets and liabilities included on the balance sheets are as follows:

As at Dec. 31	2006	2005
Balance Sheet		
Price risk management assets		
Current	**$ 61.0**	$ 63.8
Long-term	**21.9**	13.8
Price risk management liabilities		
Current	**(30.3)**	(58.3)
Long-term	**(1.0)**	(8.6)
Net price risk management assets outstanding	**$ 51.6**	$ 10.7

The change in fair value of contracts outstanding at Dec. 31, 2006 and 2005, as well as the changes in fair value of the net price risk management assets for 2006, is attributed to the following:

Change in fair value of net assets	Mark-to-market	Mark-to-model	Total
Net price risk management assets outstanding at Dec. 31, 2005	$ 7.4	$ 3.3	$ 10.7
Contracts realized, amortized or settled during the period	(3.8)	(4.8)	(8.6)
Changes in values attributable to market price and other market changes	(6.0)	0.3	(5.7)
New contracts entered into during the current calendar year	10.4	0.1	10.5
Changes in values attributable to discontinued hedge treatment of certain contracts	44.7	–	44.7
Net price risk management assets outstanding at Dec. 31, 2006	**$ 52.7**	**$ (1.1)**	**$ 51.6**

At Dec. 31, 2006, net price risk management assets and liabilities increased $40.9 million compared to Dec. 31, 2005, primarily due to certain contracts at Centralia Coal no longer receiving hedge accounting treatment.

II. Hedging Activities

The corporation uses energy derivatives, including physical and financial swaps, and forwards to manage its exposure to changes in electricity and natural gas prices. At Dec. 31, 2006, details of the corporation's hedging position were as follows:

	Fixed price payor notional amount (GJ)	Fixed price receiver notional amount (MWh)	Maximum term in months
Commodity hedges (thousands)	4,340.2	31,272.9	72

The fair value of these hedges is a $272.8 million liability (2005 – $382.6 million).

D. Credit Risk Management

The corporation actively manages its exposure to credit risk by assessing the ability of counterparties to fulfill their obligations under the related contracts prior to entering into such contracts, and continually monitors these exposures. For commodity trading and origination, the corporation sets strict credit limits for each counterparty and halts trading activities with the counterparty if the limits are exceeded. The corporation makes detailed assessments of the credit quality of all counterparties and, where appropriate, obtains corporate guarantees and/or letters of credit to support the ultimate collection of these receivables. TransAlta is exposed to minimal credit risk for Alberta Generation Power Purchase Arrangements (PPA) as all receivables are guaranteed by letters of credit.

The maximum credit exposure to any one customer for commodity trading, excluding the California market receivables discussed above and including the fair value of open trading positions, is $11.3 million.

7. INCOME TAXES

The corporation follows Canadian GAAP for non-regulated entities for all electricity generation operations and as a result, future income taxes have been recorded for all operations.

A. Statements of Earnings

I. Rate Reconciliations

Year ended Dec. 31		2006		2005		2004
				(Restated, Note 1)		(Restated, Note 1)
(Loss) earnings from continuing operations before income taxes	$	**(80.9)**	$	213.9	$	206.2
Statutory Canadian federal and provincial income tax rate (%)		**32.5**		33.6		33.9
Expected (recovery) taxes on income	$	**(26.3)**	$	71.9	$	69.8
Increase (decrease) in income taxes resulting from:						
Lower effective foreign tax rates		**(32.5)**		(29.2)		(22.1)
Asset impairment and mine closure charges recognized at higher tax rate		**(9.2)**		–		–
Resolution of uncertain tax positions		**–**		(13.0)		(6.8)
Resource allowance (net of non-deductible royalties)		**(0.8)**		(1.4)		(1.6)
Manufacturing and processing rate reduction		**–**		(1.3)		(1.7)
Capital taxes		**3.2**		10.0		10.3
Effect of tax rate changes[1]		**(55.3)**		–		(7.8)
Statutory and other rate differences[2]		**(4.4)**		3.3		2.4
Unrecognized future income tax assets		**5.1**		1.5		6.1
Other		**(5.6)**		(2.2)		(2.0)
Income tax (recovery) expense	$	**(125.8)**	$	39.6	$	46.6
Effective tax rate (%)		**155.5**		18.5		22.6

1 Effect of tax rate changes – Effect of tax rate changes on opening future income tax assets/liabilities.

2 Statutory and other rate differences – Adjustment of different statutory rates applied to current year's earnings that are taxed in future years or other jurisdictions.

The corporation's operations are complex, and the computation and provision for income taxes involves tax interpretations, regulations and legislation that are continually changing. The corporation's tax filings are subject to audit by taxation authorities. The outcome of some audits may change the tax liability of the corporation. Management believes it has adequately provided for income taxes based on all information currently available.

II. Components of Income Tax Expense

Year ended Dec. 31		2006		2005		2004
				(Restated, Note 1)		(Restated, Note 1)
Current tax expense	$	**37.9**	$	34.0	$	33.6
Future income tax (benefit) expense related to the origination and reversal of temporary differences		**(108.4)**		9.4		20.8
Future income tax (benefit) expense resulting from changes in tax rates or laws		**(55.3)**		(3.8)		(7.8)
Income tax (recovery) expense	$	**(125.8)**	$	39.6	$	46.6

B. Balance Sheets

Significant components of the corporation's future income tax assets and (liabilities) are as follows:

As at Dec. 31		2006		2005
				(Restated, Note 1)
Net operating and capital loss carryforwards		**255.4**		260.5
Future site restoration costs		**79.5**		82.6
Unrealized losses on electricity trading contracts		**27.9**		10.5
Property, plant and equipment		**(803.6)**		(947.8)
Unrealized gains on electricity trading contracts		**(43.0)**		(12.6)
Other deductible temporary differences		**85.1**		46.5
	$	**(398.7)**	$	(560.3)

Presented in the balance sheet as follows:

As at Dec. 31	2006	2005 (Restated, Note 1)
Assets		
Current	$ 25.8	$ 26.6
Long-term	294.0	170.1
Liabilities		
Current	(19.9)	(18.2)
Long-term	(698.6)	(738.8)
	$ (398.7)	$ (560.3)

As at Dec. 31, 2006, there are income tax loss carryforwards of $35.7 million (2005 – $37.5 million) for which no tax benefit has been recognized. These losses begin to expire in 2013.

8. RESTRICTED CASH

Restricted cash is mostly comprised of an investment in Notes held in trust as security for a subsidiary's obligation under a credit derivative agreement. Should the subsidiary fail to perform its obligations under this agreement, the counterparty has the right to retain the Notes in satisfaction of the subsidiary's obligation. The Notes earn interest at six month London Interbank Offered Rate (LIBOR) and mature in 2016.

Restricted cash is also comprised of debt service funds which are legally restricted, and require the maintenance of specific minimum balances equal to the next debt service payment, and amounts restricted for capital and maintenance expenditures.

9. INVESTMENTS

As at Dec. 31	2006	2005
Investment in oil and gas companies	$ –	$ 3.0
Investment in Mexico	154.5	411.3
	$ 154.5	$ 414.3

10. LONG-TERM RECEIVABLES

The company has a right to recover a portion of future asset retirement costs. The estimated present value of these payments has been recorded as a long-term receivable.

11. PROPERTY, PLANT AND EQUIPMENT

		2006			2005		
As at Dec. 31	Depreciation rates	Cost	Accumulated depreciation and amortization	Net book value	Cost	Accumulated depreciation and amortization	Net book value
Thermal generation	3% – 33%	$ 3,685.1	$ 1,368.8	$ 2,316.3	$ 3,621.7	$ 1,202.6	$ 2,419.1
Thermal environmental equipment	4% – 13%	611.5	288.5	323.0	608.5	279.5	329.0
Mining property & equipment	4% – 33%	693.5	508.8	184.7	806.7	408.4	398.3
Gas generation	2% – 50%	2,276.5	980.9	1,295.6	2,182.9	702.2	1,480.7
Geothermal generation	3% – 33%	306.2	18.3	287.9	389.2	90.8	298.4
Hydro generation	2% – 5%	376.6	212.3	164.3	348.9	197.2	151.7
Wind generation	2% – 3%	207.8	25.2	182.6	205.5	17.9	187.6
Capital spares and other	2% – 50%	251.3	101.0	150.3	246.5	87.9	158.6
Assets under construction	–	–	–	–	–	–	–
Coal rights [1]	–	82.1	25.4	56.7	82.1	20.1	62.0
Land	–	53.7	–	53.7	40.0	–	40.0
Transmission systems	2% – 20%	43.7	16.9	26.8	40.9	14.8	26.1
		$ 8,588.0	$ 3,546.1	$ 5,041.9	$ 8,572.9	$ 3,021.4	$ 5,551.5

1 *Coal rights are amortized on a unit of production basis, based on the estimated mine reserve.*

The corporation had no capitalization of PP&E in 2006 (2005 – $3.4 million; 2004 – $20.0 million).

On Nov. 27, 2006, TransAlta stopped mining at the Centralia Coal mine as a result of increased costs and unfavourable geological events. As a result, the associated mining and reclamation equipment including coal processing equipment and structures, haul roads and other equipment were written down to the lower of net book value and net realizable value and are classified as assets held for sale *(Note 12)*.

12. ASSETS HELD FOR SALE

As a result of the decision to stop mining at Centralia, all associated mining and reclamation equipment is being held for sale. All equipment has been recorded at the lower of net book value or anticipated realized proceeds. Due to the strong market for this equipment, it is anticipated that these assets will be sold during 2007. These assets are included in the Generation segment.

13. INTANGIBLE ASSETS

Intangible assets consist of power sale contracts, with rates higher than market rates at the date of acquisition, acquired in the purchase of CE Gen. Sales contracts are valued at cost and are amortized on a straight-line basis over the remaining contract period, which ranges from three to 28 years at the date of acquisition.

As at Dec. 31		**2006**				2005
	Cost	**Accumulated amortization**	**Net book value**	Cost	Accumulated amortization	Net book value
Sales contracts	**$ 473.0**	**$ 180.9**	**$ 292.1**	$ 473.7	$ 130.0	$ 343.7

14. OTHER ASSETS

As at Dec. 31	**2006**	2005
Cross-currency interest rate swaps and foreign currency forward contracts *(Note 6)*	**$ 54.4**	$ 102.6
Interest rate swaps *(Note 6)*	**25.8**	38.4
Deferred financing costs	**12.2**	18.7
Deferred license fees	**26.8**	27.1
Deferred contract costs	**16.1**	17.1
Deferred project development costs and other	**12.7**	2.7
Long-term gas transportation deals	**-**	4.4
	148.0	211.0
Less current portion	**(16.6)**	(10.9)
	$ 131.4	$ 200.1

Deferred financing costs are costs associated with the issuance of long-term debt, preferred shares and preferred securities and are being amortized on a straight-line basis over the term of the related issue.

Deferred license fees consist primarily of an Australian license that is being amortized on a straight-line basis over the useful life of the power station assets to which the license relates.

Deferred contract costs consist of prepayments related to long-term contracts, that are being amortized on a straight-line basis over the term of the related contracts.

15. SHORT-TERM DEBT

		2006		2005
As at Dec. 31	**Outstanding**	**Interest [1]**	Outstanding	Interest [1]
Commercial paper	**$ 199.3**	**4.3%**	$ 12.5	3.3%
Bank debt [2]	**162.6**	**4.4%**	0.6	0.0%
	$ 361.9		$ 13.1	

1 *Interest is an average rate weighted by principal amounts outstanding before the effect of hedging.*
2 *Bank debt is in the form of Bankers' Acceptances.*

The short-term debt instruments are drawn on the $1.5 billion committed syndicated bank credit facility.

16. LONG-TERM DEBT AND NET INTEREST EXPENSE

A. Amounts Outstanding

		2006		2005
As at Dec. 31	**Outstanding**	**Interest [1]**	Outstanding	Interest [1]
Debentures, due 2007 to 2033	**$ 1,146.4**	**6.1%**	$ 1,496.1	6.2%
Senior notes, US$600.0 million	**693.2**	**6.3%**	694.0	6.3%
Non-recourse debt	**334.3**	**7.7%**	363.8	7.7%
Notes payable – Windsor-Essex plant, due 2007 to 2014	**46.9**	**7.4%**	51.1	7.4%
Preferred securities, due 2050	**175.0**	**7.8%**	175.0	7.8%
	$ 2,395.8		$ 2,780.0	
Less current portion	**424.7**		396.4	
	$ 1,971.1		$ 2,383.6	

1 *Interest is an average rate weighted by principal amounts outstanding before the effect of hedging.*

The debentures bear interest at fixed rates ranging from 4.2 per cent to 7.3 per cent. A floating charge on the property and assets of TransAlta Utilities (TAU) has been provided as collateral for $265.0 million of the debentures as at Dec. 31, 2006. The interest rate on $200.0 million of the debentures has been converted to floating rates based on bankers' acceptance rates using receive fixed, pay floating interest rate swaps maturing in 2011 *(Note 6)*. Debentures of $100.0 million maturing in 2023 and $50.0 million maturing in 2033 are redeemable at the option of the holder in 2008 and 2009, respectively. Debentures in the amount of $350.0 million matured in 2006.

The senior notes bear an interest rate of 5.75 per cent and mature in 2013. The US$300.0 million has been converted to a floating rate based on LIBOR using receive fixed, pay floating interest rate swaps maturing in 2013. The notes bear interest at 6.75 per cent and mature on July 15, 2012. All senior notes have been designated as a hedge of the corporation's net investment in U.S. and Mexican operations *(Note 6)*.

The non-recourse debt consists of project financing debt, debt securities and senior secured bonds of CE Gen and debt related to the Wailuku acquisition. The CE Gen related assets have been pledged as security for the project financing debt, which has maturity dates ranging from 2007 to 2008 and a fixed interest rate of 8.56 per cent. The CE Gen debt securities are non-recourse, have maturity dates ranging from 2010 to 2018 and interest rates ranging from 7.48 per cent to 8.30 per cent. The outstanding balance of the non-recourse senior secured bonds as of Dec. 31, 2006 was $173.2 million, which bear interest at 7.42 per cent and are due in 2018. The Wailuku debt at Dec. 31, 2006 is US$9.2 million and bears interest at a floating rate of 3.65%.

The Windsor-Essex plant notes bear interest at fixed rates and are recourse to the corporation through a standby letter of credit.

The preferred securities bear interest of 7.75 per cent and are due in 2050. In 2006, the corporation provided irrevocable notice to redeem the preferred securities on Jan. 2, 2007 at a redemption price equal to 100 per cent of the principal amount of the preferred securities plus accrued and unpaid distributions thereon to the date of such redemption. The corporation had the option to elect to defer coupon payments on the preferred securities and settle deferred coupon payments in either cash or common shares of the corporation. Historically, the coupon payments have been in cash; therefore, the preferred securities have no dilutive effect on earnings per share. Supplemental diluted earnings per share for 2006 from continuing operations and net earnings as though the coupon payments were settled with shares were $0.22 (2005 – $0.88; 2004 – $0.82) and $0.22 (2005 – $0.94; 2004 – $0.87). Interest accretion at the coupon rate is included in interest expense.

B. Principal Repayments

2007	$ 424.7
2008	157.1
2009	241.3
2010	33.0
2011	251.9
2012 and thereafter	1,287.8
Total	$ 2,395.8

C. Interest Expense

Year ended Dec. 31	**2006**	2005	2004
Interest on long-term debt	**$ 155.5**	$ 169.3	$ 181.4
Interest on short-term debt	**12.7**	14.9	11.4
Interest on preferred securities	**13.6**	16.5	44.5
Interest income	**(13.3)**	(8.7)	(9.9)
Capitalized interest	**–**	(3.4)	(20.0)
Net interest expense	**$ 168.5**	$ 188.6	$ 207.4

D. Guarantees

In the normal course of operations, TransAlta and certain of its subsidiaries enter into agreements to provide financial or performance assurances to third parties. This includes guarantees and letters of credit which are entered into to support or enhance creditworthiness in order to facilitate the extension of sufficient credit for CD&M trading activities, treasury hedging, Generation construction projects, equipment purchases and mine reclamation obligations.

At Dec. 31, 2006, the corporation had letters of credit outstanding of $234.0 million and US$344.9 million. The letters of credit were issued to counterparties that have credit exposure to certain subsidiaries. If the corporation or its subsidiary does not pay amounts due under the contract, the counterparty may present its claim for payment to the financial institution, which in turn will request payment from the corporation. Any amounts owed by the corporation or its subsidiaries are reflected in the consolidated balance sheet. All letters of credit expire in 2007 and are expected to be renewed, as needed, through the normal course of business.

The corporation has arranged for the issuance of a surety bond in the amount of US$192.0 million in support of mine reclamation obligations at the Centralia mine.

TransAlta has provided guarantees of subsidiaries' obligations under contracts that facilitate physical and financial transactions in various derivatives. To the extent liabilities related to these guaranteed contracts exist for trading activities, they are included in the consolidated

balance sheet. To the extent liabilities exist related to these guaranteed contracts for hedges, they are not recognized on the consolidated balance sheet. The guarantees provided for under all contracts facilitating physical and financial transactions in various derivatives at Dec. 31, 2006 were to a maximum of $1.9 billion. In addition, the corporation has a number of unlimited guarantees. The fair value of the trading and hedging positions under contracts where TransAlta has a net liability at Dec. 31, 2006, under the limited and unlimited guarantees, was $285.3 million (2005 – $559.6 million).

TransAlta has also provided guarantees of subsidiaries' obligations to perform and make payments under various other contracts. The amount guaranteed under these contracts at Dec. 31, 2006 was $788.3 million (2005 – $645.3 million). To the extent actual obligations exist under the performance guarantees at Dec. 31, 2006, they are included in accounts payable and accrued liabilities.

The corporation has approximately $840 million of undrawn collateral available to secure these exposures.

A subsidiary of the corporation has entered into a credit derivative agreement. Under the terms of the agreement, upon any specified credit event by the corporation or any named subsidiary, the counterparty would have the right to deliver senior debt of the corporation or any named subsidiary in return for payment. The debt obligations referenced by this agreement have been included in the consolidated balance sheet and also include US$295 million of loans made to subsidiaries of the corporation *(Note 8)*.

17. DEFERRED CREDITS AND OTHER LONG-TERM LIABILITIES

As at Dec. 31		**2006**		2005
Asset retirement obligations	**$**	**328.5**	$	249.2
Anticipated future Centralia mine closure liability *(Note 2)*		**25.6**		–
Deferred revenues and other		**19.7**		21.8
Power purchase arrangement in limited partnership		**27.1**		29.2
Accrued benefit liability *(Note 26)*		**58.0**		49.3
Cross-currency interest rate swaps and foreign currency forward contracts *(Note 6)*		**15.1**		14.8
Fair value of swap transaction with limited partnership		**–**		1.6
	$	**474.0**	$	365.9
Less current portion		**(50.6)**		(33.8)
	$	**423.4**	$	332.1

The power purchase arrangement in the limited partnership represents the fair value adjustments for the Sheerness Generating Station to deliver power at less than the prevailing market price at the time of the acquisition of the plant by TA Cogen.

Deferred revenue and other includes future revenues related to the sale of emission credits.

Anticipated future Centralia mine closure liability is the expected future amount of severance payments and other expenses incurred as a result of closing the mine.

A reconciliation between the opening and closing asset retirement obligation balances is provided below:

Balance, Dec. 31, 2004	$	238.1
Liabilities incurred in period		12.3
Liabilities settled in period		(29.4)
Accretion expense		19.3
Revision in estimated timing and amount of cash flows		25.6
Change in foreign exchange rates		(16.7)
Balance, Dec. 31, 2005	$	249.2
Liabilities incurred in period		7.6
Liabilities settled in period		(29.2)
Accretion expense		21.5
Revisions in estimated timing and amount of cash flows		79.1
Change in foreign exchange rates		0.3
Balance, Dec. 31, 2006	**$**	**328.5**

As a result of the decision to stop mining at Centralia, reclamation activities have been accelerated from the original end of mine life of 2032. This change in timing of cash flows increased the asset retirement by $34.0 million. The remainder of the change is from revised estimates at our other facilities.

TransAlta estimates the undiscounted amount of cash flow required to settle the asset retirement obligations is approximately $1.1 billion, which will be incurred between 2007 and 2072. The majority of the costs will be incurred between 2020 and 2030. A discount rate of eight per cent and an inflation rate of two per cent were used to calculate the carrying value of the asset retirement obligations. At Dec. 31, 2006, the corporation had a surety bond in the amount of US$192.0 million (2005 – US$192.0 million) in support of future retirement obligations at the Centralia mine. At Dec. 31, 2006, the corporation had letters of credit in the amount of $47.3 million (2005 – $60.8 million) in support of future retirement obligations at the Alberta mines.

18. NON-CONTROLLING INTERESTS

A. Statements of Earnings

Year ended Dec. 31	2006	2005	2004
TransAlta Power's limited partnership interest in TA Cogen *(Note 27)*	$ 35.3	$ 2.1	$ 31.5
25 per cent interest in Saranac Partnership not owned by CE Gen	16.2	16.4	14.5
	$ 51.5	$ 18.5	$ 46.0

B. Balance Sheets

As at Dec. 31	2006	2005
TransAlta Power's limited partnership interest in TA Cogen	$ 502.6	$ 525.0
25 per cent interest in Saranac Partnership not owned by CE Gen	32.4	33.6
	$ 535.0	$ 558.6

19. COMMON SHARES

A. Issued and Outstanding

The corporation is authorized to issue an unlimited number of voting common shares without nominal or par value.

Year ended Dec. 31	2006		2005		2004	
	Common shares (millions)	Amount	Common shares (millions)	Amount	Common shares (millions)	Amount
Issued and outstanding, beginning of year	198.7	$ 1,697.9	194.1	$ 1,611.9	190.7	$ 1,555.7
Issued as a public offering and other	–	–	–	–	–	–
Issued under dividend reinvestment and share purchase plan	3.0	70.0	3.5	68.1	3.4	55.3
Issued on purchase of Vision Quest	–	–	–	0.2	–	0.7
Issued for cash under stock option plans	0.6	14.3	1.0	16.3	0.1	1.1
Issued under Performance Share Ownership Plan	0.1	0.1	0.1	1.2	–	1.1
Repurchased by the corporation	–	–	–	–	(0.1)	(1.2)
Employee share purchase loans	–	0.1	–	0.2	–	(0.8)
	202.4	$ 1,782.4	198.7	$ 1,697.9	194.1	$ 1,611.9

At Dec. 31, 2006, the corporation had 202.4 million (2005 – 198.7 million; 2004 – 194.1 million) common shares issued and outstanding plus outstanding employee stock options to purchase an additional 2.2 million shares (2005 – 2.9 million; 2004 – 2.9 million).

In February 2004, TransAlta announced a normal course issuer bid to repurchase up to 3.0 million common shares for cancellation. In 2005, no shares were repurchased. In 2004, 143,500 shares were repurchased and no shares were repurchased during 2003. The $1.1 million in 2004 in excess of the repurchase price over the average net book value of the common shares was charged to retained earnings.

B. Shareholder Rights Plan

The primary objective of the shareholder rights plan is to provide the corporation's Board of Directors sufficient time to explore and develop alternatives for maximizing shareholder value if a takeover bid is made for the corporation and to provide every shareholder with an equal opportunity to participate in such a bid. The plan was originally approved in 1992, and has been revised from time to time for conformity with current practices.

When an acquiring shareholder acquires 20 per cent or more of the outstanding common shares of the corporation and that shareholder does not make a bid for all of the common shares outstanding, each shareholder other than the acquiring shareholder may receive one right for each common share owned. Each right will entitle the holder to acquire an additional $160 worth of common shares for $80.

C. Dividend Reinvestment and Share Purchase (DRASP) Plan

Under the terms of the DRASP plan, participants are able to purchase additional common shares by reinvesting dividends. In 2006, 3.0 million (2005 – 3.5 million; 2004 – 3.4 million) common shares were purchased under this program for $70.0 million (2005 – $68.1 million; 2004 – $55.3 million). In 2006, the corporation announced that effective Jan. 1, 2007, the corporation will amend the DRASP plan. As a result, after, Dec. 31, 2006, the five per cent discount on the price of shares purchased through the DRASP plan and issued from treasury will be suspended. After Dec. 31, 2006, shares purchased under the DRASP plan will be acquired in the open market at 100 per cent of the average purchase price of common shares acquired on the Toronto Stock Exchange on the investment dates. Shares issuable under the DRASP plan have not been registered under any U.S. Federal or State Securities laws and U.S. persons or residents are not eligible to participate in the DRASP plan.

D. Earnings Per Share (EPS)

Year ended Dec. 31	2006		2005		2004	
	Numerator	**Denominator**	Numerator	Denominator	Numerator	Denominator
				(Restated, Note 1)		(Restated, Note 1)
Basic EPS from continuing operations	**44.9**	**200.8**	174.3	196.8	159.6	192.7
Impact of PSOP	**–**	**0.4**	–	0.4	–	0.1
Diluted EPS from continuing operations	**44.9**	**201.2**	174.3	197.2	159.6	192.8

20. ACQUISITIONS AND DISPOSALS

A. Acquisitions

On Feb. 17, 2006, the corporation acquired a 50 per cent ownership in Wailuku River Hydroelectric L.P. (Wailuku) for US$1.0 million (Cdn$1.2 million). The acquisition is accounted for using the purchase method of accounting. The following table summarizes the estimated fair value of the assets acquired and liabilities assumed at the date of acquisition. The financial operations of Wailuku have been proportionately consolidated with those of TransAlta.

Net assets acquired at assigned values:		
Working capital, including cash of $0.3 million	$	(2.7)
Property, plant and equipment		26.2
Long-term debt, including current portion		(22.3)
Total	$	1.2
Consideration:		
Cash	$	1.2

B. Disposals

On Dec. 1, 2004, TransAlta completed the sale of its 50 per cent interest in the 220 megawatt (MW) Meridian cogeneration facility located in Lloydminster, Saskatchewan to TransAlta Cogeneration, L.P. (TA Cogen), owned 50.01 per cent by TransAlta and 49.99 per cent by TransAlta Power, L.P. (TA Power), for its fair value of $110.0 million. TA Cogen financed the acquisition through the use of $50.0 million of cash on hand, by the issuance of $30.0 million of units to each of TransAlta Energy Corporation (TEC) and TA Power and by an advance to TEC for $30.0 million. The advance outstanding at Dec. 31, 2006 was $5.0 million (2005 – $5.0 million) and is included in accounts receivable.

On July 31, 2003, TransAlta completed the sale of its 50 per cent interest in the two-unit 756 MW coal-fired Sheerness Generating Station to TA Cogen for $630.0 million. TransAlta received cash proceeds of $149.9 million, $315.0 million in TA Cogen units and $165.1 million in TransAlta Power units. As part of the financing, and concurrent with the sale, TransAlta Power issued 17.75 million partnership units and 17.75 million warrants to the public for gross proceeds of $165.1 million, and 17.75 million partnership units to TransAlta for gross proceeds of $165.1 million. As a result of the unit issuance, TransAlta's ownership interest in TransAlta Power on July 31, 2003 was approximately 26 per cent. Each warrant, when exercised, was exchangeable for one TA Power unit at any time until Aug. 3, 2004. As the warrants were exercised, TransAlta sold TransAlta Power units back to TransAlta Power for $9.30 per unit, reducing its ownership interest in TransAlta Power and increasing cash proceeds. As a result of exercising warrants and the subsequent sale of TA Power units by the corporation, TransAlta's ownership interest in TA Power was reduced to 0.01 per cent held by TransAlta Power Ltd., the general partner of TransAlta Power, as at Dec. 31, 2004.

For the year ended Dec. 31, 2004, TransAlta recognized $44.8 million of dilution gains on the exercise of warrants and subsequent sale of units.

21. RELATED PARTY TRANSACTIONS

In August 2006, TransAlta entered into an agreement with CE Gen, a corporation jointly controlled by TransAlta and MidAmerican, a subsidiary of Berkshire Hathaway, whereby TransAlta buys available power from certain CE Gen subsidiaries at a fixed price. In addition, CE Gen has entered into contracts with related parties to provide administrative and maintenance services.

On March 8, 2006, TransAlta Cogeneration LP (TA Cogen) entered into an agreement with TEC whereby TEC provided a financial fixed-for-floating price swap to TA Cogen at market prices during planned maintenance at the Sheerness plant in the second quarter of 2006. The swap was settled in the second quarter of 2006 and did not have a material effect on the financial statements. TA Cogen is 50.01 per cent owned by TransAlta and TEC is 100 per cent owned by TransAlta.

For the period November 2002 to November 2012, TA Cogen entered into various transportation swap transactions with a wholly owned subsidiary of TransAlta, TEC *(Note 6)*. TEC operates and maintains TA Cogen's three combined-cycle power plants in Ontario and a plant in Fort Saskatchewan, Alberta. TEC also provides management services to Sheerness, which is operated by Canadian Utilities. The business purpose of these transportation swaps is to provide TA Cogen with the delivery of fixed price gas without being exposed to escalating costs of pipeline transportation for three of its plants over the period of the swap. The notional gas volume in the transaction was the total delivered fuel for each of the facilities. Exchange amounts are based on the market value of the contract. TransAlta entered into an offsetting contract with an external third party, therefore TransAlta has no risk other than counterparty risk.

On March 8, 2005, TA Cogen entered into an agreement with TEC whereby TEC provided a financial fixed-for-floating price swap to TA Cogen during planned maintenance at Sheerness in the second quarter of 2005. This transaction did not have a material impact upon the financial statements of TransAlta.

On Dec. 1, 2004, TransAlta completed the sale of its 50 per cent interest in the 220 MW Meridian cogeneration facility located in Lloydminster, Saskatchewan to TA Cogen for its fair value of $110.0 million. TA Cogen (owned 50.01 per cent by TransAlta and 49.99 per cent by TransAlta Power) financed the acquisition through the use of $50.0 million of cash on hand and by the issuance of $30.0 million of units to each of TransAlta Power and TEC. TA Cogen also issued an advance to TEC for $30.0 million. The advance outstanding at Dec. 31, 2005 was $5.0 million (2004 – $28.0 million) and is included in accounts receivable. TransAlta recorded a gain of $11.5 million after-tax or $0.06 per common share ($17.7 million pre-tax) in 2004.

22. OTHER CONTINGENCIES

In March 2003, FERC completed its investigation of natural gas and power markets and indicated that the total industry refunds for price overcharges will be higher than originally anticipated.

In June 2003, FERC issued two show cause orders, the Partnership Gaming Order and the Gaming Practices Order, in which TransAlta's U.S. subsidiaries were named. These orders required TransAlta to justify certain trading activities in California between Oct. 1, 2000 and June 20, 2001. In response to FERC's show cause orders, TransAlta confirmed that it did not engage in gaming behaviour. Based on the information provided by TransAlta, FERC Trial Staff filed a Motion to Dismiss with respect to TransAlta in the two show cause proceedings. On Jan. 22, 2004, FERC granted the FERC Trial Staff's motion to dismiss TransAlta from both the Partnership Gaming Order and the Gaming Practices Order. FERC found that TransAlta did not engage in prohibited gaming practices.

On May 30, 2002, the California Attorney General's Office filed civil complaints in the state court of California against eight wholesale power companies, including TransAlta. The complaint alleges violations of California's unfair business practices law in connection with rates charged for wholesale electricity sales. The state court denied the Attorney General's complaint and granted an order to dismiss the claims against TransAlta. The Attorney General dropped its appeal of this decision on November 2, 2004; therefore, the decision is final as of such date.

The Canadian Government introduced its *Clean Air Act* on Oct. 19, 2006, designed to regulate emissions of greenhouse gases and air pollutants. The proposed Act is currently under review in Parliament and may be subject to changes. Neither targets for emission reductions nor the associated compliance mechanisms have been announced, and, we are therefore unable to estimate the impact on our operations. Emission targets under the *Clean Air Act* are also anticipated for mercury; however, they are expected to be superseded by provincial standards already in place, requiring a 70 per cent reduction in emissions by 2010. TransAlta is in the process of meeting that requirement.

The corporation is involved in various other claims and legal actions arising from the normal course of business. The corporation does not expect that the outcome of these proceedings, having regard to insurance available to it, and the amounts reserved in respect of such claims, will have a materially adverse effect on the corporation as a whole.

23. COMMITMENTS

A significant portion of the corporation's electricity and thermal sales revenues are subject to PPAs and long-term contracts. Commencing Jan. 1, 2001, a large portion of Alberta's coal generating assets became subject to long-term PPAs for a period approximating the remaining life of each plant or unit. These PPAs set a production requirement and availability target for each plant or unit and the price at which each MWh will be supplied to the customer. Remaining coal capacity in Alberta is sold on the open electricity market.

A portion of Poplar Creeks' gas-fired capacity and all of its steam is committed to the customer under a long-term contract. The remaining capacity may be taken by the customer at specified rates or sold on the open electricity market by TransAlta. Other gas-fired facilities in Alberta supply steam and/or electricity to specified customers under long-term contracts with additional requirements for availability, reliability and other plant-specific performance measures.

For Mexico, the plants' energy production is subject to 25-year contracts with the Comisión Federal de Electricidad. These contracts set availability targets and the price at which the plant will be paid per kilowatt of available capacity, as well as plant efficiency targets for recovery of fuel costs based on market prices.

At Sarnia, there are 20-year contracts with a customer group with three five-year options for extensions to the contracts. The contracts allow for up to 40 per cent of the plant's maximum capacity. These contracts set payments for peak megawatts, total megawatt hours and steam consumed, while TransAlta assumes the availability and heat rate risk. Effective Jan. 1, 2006, TransAlta signed a five-year agreement with the Ontario Power Authority to supply 400 MW of electricity to the Ontario electricity market. The remaining capacity is available for export to the merchant market, based on market conditions. Production at the remaining Ontario plants is subject to contracts expiring in seven to 12 years.

Mississauga and Windsor-Essex have contracts that set availability targets and the price at which the plant will be paid per MWhs produced, as well as risk sharing of fuel costs based on market prices. The terms of the Ottawa plant for electricity are similar, except for the risk sharing of fuel costs. Thermal energy contracts for these Ontario plants expire the same time as the energy production contracts and are with a different customer base. These contracts set payments for volumes consumed, while TA Cogen assumes the heat rate risk.

At Centralia Coal, a significant portion of production is subject to short- to medium-term energy sales contracts. In addition, a portion of the corporation's energy sales from its gas plants are subject to medium- to long-term energy sales contracts.

Centralia Coal has various coal supply and associated rail transport contracts to provide Powder River Basin (PRB) coal for the use in production. At Alberta Thermal, the mines are operated by a third party who is paid a fixed amount to provide a budgeted supply of coal. Both of these amounts are included under coal supply and mining agreements.

The corporation has entered into a number of long-term gas purchase agreements, transportation and transmission agreements, royalty and right-of-way agreements in the normal course of operations.

Approximate future payments under the fixed price purchase contracts, operating lease and mining agreements are as follows:

	Fixed price gas purchase contracts	Operating leases	Coal supply and mining agreements	Total
2007	$ 52.2	$ 14.8	$ 183.6	$ 250.6
2008	54.0	11.1	169.4	234.5
2009	31.0	9.9	64.4	105.3
2010	8.2	9.1	20.9	38.2
2011	8.2	9.2	20.4	37.8
2012 and thereafter	55.0	79.3	271.6	405.9
Total	$ 208.6	$ 133.4	$ 730.3	$ 1,072.3

24. SEGMENT DISCLOSURES

A. Description of Reportable Segments

The corporation has two reportable segments: Generation and Corporate Development & Marketing (CD&M). TransAlta's segments are supported by a corporate group that provides finance, treasury, legal, environmental health & safety, sustainable development, corporate communications, government relations, information technology, human resources and other administrative support.

Each business segment assumes responsibility for its operating results measured as operating income or loss.

The Generation segment owns coal, gas, wind, geothermal and hydro power plants in Canada, the United States and Australia, and generates its revenue from the sale of electricity, steam, gas and ancillary services. Generation expenses include CD&M's intersegment charge for energy marketing and financial risk management services in the amount of $27.8 million (2005 – $26.0 million; 2004 – $26.0 million).

The CD&M segment derives revenue and earnings from the wholesale trading of electricity and other energy-related commodities and derivatives not supported by TransAlta-owned generation assets. CD&M also utilizes contracts of various durations for the forward sales of electricity and purchases of natural gas and transmission capacity to effectively manage available generating capacity and fuel and transmission needs on behalf of Generation. These results are included in the Generation segment. Operating expenses are net of the intersegment charges for provision of these energy marketing, financial risk management, commercial, portfolio and regulatory management services of $27.8 million (2005 – $26.0 million; 2004 – $26.0 million).

The accounting policies of the segments are the same as those described in *Note 1*. Intersegment transactions are accounted for on a cost recovery basis that approximates market rates. Segment revenues are net of intersegment transactions.

B. Reported Segment Earnings and Segment Assets

I. Earnings Information

Year ended Dec. 31, 2006	**Generation**	**CD&M**	**Corporate**	**Total**
Revenues	**$ 2,611.9**	**$ 184.6**	**$ –**	**$ 2,796.5**
Trading purchases	**–**	**(118.9)**	**–**	**(118.9)**
Fuel and purchased power *(Note 2)*	**(1,186.2)**	**–**	**–**	**(1,186.2)**
Gross margin	**1,425.7**	**65.7**	**–**	**1,491.4**
Operations, maintenance and administration	**458.3**	**36.9**	**86.1**	**581.3**
Depreciation and amortization	**396.9**	**1.3**	**12.1**	**410.3**
Taxes, other than income taxes	**21.1**	**–**	**0.2**	**21.3**
Intersegment cost allocation	**27.8**	**(27.8)**	**–**	**–**
Operating expenses	**904.1**	**10.4**	**98.4**	**1,012.9**
Mine closure charges *(Note 2)*	**191.9**	**–**	**–**	**191.9**
Asset impairment charges *(Note 3)*	**130.0**	**–**	**–**	**130.0**
Operating income (loss)	**$ 199.7**	**$ 55.3**	**$ (98.4)**	**$ 156.6**
Foreign exchange loss				**(0.5)**
Net interest expense				**(168.5)**
Equity loss				**(17.0)**
Loss from continuing operations before income taxes and non-controlling interests				**$ (29.4)**

Year ended Dec. 31, 2005 *(Restated, Note 1)*	Generation	CD&M	Corporate	Total
Revenues	$ 2,607.5	$ 231.0	$ –	$ 2,838.5
Trading purchases	–	(174.1)	–	(174.1)
Fuel and purchased power	(1,222.4)	–	–	(1,222.4)
Gross margin	1,385.1	56.9	–	1,442.0
Operations, maintenance and administration	481.1	38.5	76.4	596.0
Depreciation and amortization	354.9	1.7	11.3	367.9
Taxes, other than income taxes	21.3	–	–	21.3
Intersegment cost allocation	26.0	(26.0)	–	–
Operating expenses	883.3	14.2	87.7	985.2
Asset impairment charges *(Note 3)*	36.2	–	–	36.2
Operating income (loss)	$ 465.6	$ 42.7	$ (87.7)	$ 420.6
Foreign exchange gain				1.3
Net interest expense				(188.6)
Equity loss				(0.9)
Earnings from continuing operations before income taxes and non-controlling interests				$ 232.4

Year ended Dec. 31, 2004 *(Restated, Note 1)*	Generation	CD&M	Corporate	Total
Revenues	$ 2,341.7	$ 244.5	$ –	$ 2,586.2
Trading purchases	–	(197.7)	–	(197.7)
Fuel and purchased power	(1,035.2)	–	–	(1,035.2)
Gross margin	1,306.5	46.8	–	1,353.3
Operations, maintenance and administration	450.0	31.3	66.2	547.5
Depreciation and amortization	343.5	2.0	12.0	357.5
Taxes, other than income taxes	20.5	–	–	20.5
Intersegment cost allocation	26.0	(26.0)	–	–
Operating expenses	840.0	7.3	78.2	925.5
Prior period regulatory decision *(Note 4)*	–	(22.9)	–	(22.9)
Gain on sale of TransAlta Power partnership units *(Note 20)*	44.8	–	–	44.8
Gain on sale of Meridian cogeneration facility *(Note 20)*	17.7	–	–	17.7
Operating income (loss) before corporate allocations	$ 529.0	$ 16.6	$ (78.2)	$ 467.4
Foreign exchange gain				0.7
Net interest expense				(207.4)
Equity loss				(8.5)
Earnings from continuing operations before income taxes and non-controlling interests				$ 252.2

II. Selected Balance Sheet Information

Dec. 31, 2006	**Generation**	**CD&M**	**Corporate**	**Total**
Goodwill	**$ 108.0**	**$ 29.5**	**$ –**	**$ 137.5**
Total segment assets	**$ 6,159.3**	**$ 185.0**	**$ 1,115.8**	**$ 7,460.1**

Dec. 31, 2005 *(Restated, Note 1)*	Generation	CD&M	Corporate	Total
Goodwill	$ 108.1	$ 29.5	$ –	$ 137.6
Total segment assets	$ 6,460.6	$ 293.2	$ 939.3	$ 7,693.1

III. Selected Cash Flow Information

Year ended Dec. 31, 2006	**Generation**	**CD&M**	**Corporate**	**Total**
Capital expenditures	**$ 205.9**	**$ 1.6**	**$ 16.2**	**$ 223.7**
Acquisitions	**$ 1.2**	**$ –**	**$ –**	**$ 1.2**

Year ended Dec. 31, 2005				
Capital expenditures	$ 313.6	$ 1.5	$ 10.8	$ 325.5

Year ended Dec. 31, 2004				
Capital expenditures	$ 332.3	$ 2.3	$ 11.1	$ 345.7

IV. Reconciliation

Year ended Dec. 31	2006	2005	2004
Depreciation and amortization expense for reportable segments	$ 410.3	$ 367.9	$ 357.5
Mining equipment depreciation, included in fuel and purchased power	49.0	49.9	53.3
Accretion expense, included in depreciation and amortization expense	(21.5)	(19.3)	(19.3)
Other	–	2.4	(1.4)
Depreciation and amortization expense per statements of cash flows	$ 437.8	$ 400.9	$ 390.1

C. Geographic Information

I. Revenues

	2006	2005	2004
Canada	$ 1,771.5	$ 1,716.1	$ 1,662.7
U.S.	934.2	1,026.2	833.0
Australia	90.8	96.2	90.5
	$ 2,796.5	$ 2,838.5	$ 2,586.2

II. Property, Plant and Equipment and Goodwill

	PP&E		Goodwill	
	2006	2005	2006	2005
Canada	$ 3,694.2	$ 3,789.3	$ 56.5	$ 56.5
U.S.	1,182.2	1,591.0	81.0	81.1
Australia	165.5	171.2	–	–
	$ 5,041.9	$ 5,551.5	$ 137.5	$ 137.6

25. STOCK-BASED COMPENSATION PLAN

At Dec. 31, 2006, the corporation had three types of stock-based compensation plans and an employee share purchase plan.

The corporation is authorized to grant employees options to purchase up to an aggregate of 13.0 million common shares at prices based on the market price of the shares as determined on the grant date. The corporation has reserved 13.0 million common shares for issue.

A. Fixed Stock Option Plans

I. Management Plan

The granting of options under this fixed stock option plan was discontinued in 1997. Options were granted under this plan to certain eligible employees. The options could not be exercised until one year after grant and thereafter at an amount not exceeding 20 per cent of the grant per year on a cumulative basis until the sixth year, after which the entire grant may be exercised until the tenth year, which is the expiry date.

II. Canadian Employee Plan

This plan is offered to all full-time and part-time employees in Canada at or below the level of manager. Options granted under this plan may not be exercised until one year after grant and thereafter at an amount not exceeding 25 per cent of the grant per year on a cumulative basis until the fifth year, after which the entire grant may be exercised until the tenth year, which is the expiry date.

III. U.S. Plan

This plan is offered to all full-time and part-time employees in the U.S. at or below the level of manager. Options granted under this plan may not be exercised until one year after grant and thereafter at an amount not exceeding 25 per cent of the grant per year on a cumulative basis until the fifth year, after which the entire grant may be exercised until the tenth year, which is the expiry date.

IV. Australian Phantom Plans

This plan came into effect in 2001 and was offered to all full-time and part-time employees in Australia, excluding directors and officers. Options under this plan are not physically granted; rather, employees receive the equivalent value of shares in cash when exercised. Options granted under this plan may not be exercised until one year after grant and thereafter at an amount not exceeding 25 per cent of the grant per year on a cumulative basis until the fifth year, after which the entire grant may be exercised until the tenth year, which is the expiry date.

V. Mexican Phantom Plan

The Mexican phantom plan mirrors the rules of the Australian plan, with the first grant occurring in 2005.

	Options outstanding				Options exercisable		
	Number outstanding at Dec. 31, 2006 (millions)	Weighted average remaining contractual life (years)		Weighted average exercise price	**Number exercisable at Dec. 31, 2006 (millions)**		Weighted average exercise price
Range of exercise prices							
$13.12 – $18.00	**1.3**	7.1	$	16.87	**0.5**	$	16.00
$18.01 – $23.00	**0.3**	5.0		21.05	**0.3**		21.04
$23.01 – $27.70	**0.4**	4.3		27.70	**0.5**		27.70
$13.12 – $27.70	**2.0**	6.1	$	19.95	**1.3**	$	21.55

B. Performance Stock Option Plan

In 1999, the corporation expanded enrolment in the share option program to include all Canadian employees of the corporation, excluding the level of director and above, by issuing stock options with an expiry date of 2009 and vesting dependent upon achieving certain earnings per share targets.

Year ended Dec. 31			**2006**			2005			2004
	Number of share options (millions)		**Weighted average exercise price**	Number of share options (millions)		Weighted average exercise price	Number of share options (millions)		Weighted average exercise price
Outstanding, beginning of year	**0.2**	**$**	**22.62**	0.2	$	22.44	0.2	$	22.44
Exercised	**–**		**21.99**	–		21.33	–		–
Cancelled or expired	**–**		**23.05**	–		23.05	–		–
Outstanding, end of year	**0.2**	**$**	**22.73**	0.2	$	22.62	0.2	$	22.44

At Dec. 31, 2006, the corporation had 6,000 options under this plan with an exercise price of $14.15 and a weighted average remaining contractual life of 3.0 years and 159,500 options with an exercise price of $23.05 and a weighted average remaining contractual life of 2.1 years outstanding. At Dec. 31, 2006, all outstanding options had vested.

C. Performance Share Ownership Plan (PSOP)

Under the terms of the PSOP, which commenced in 1997, the corporation was authorized to grant to employees and directors up to an aggregate of 2.0 million common shares. The number of common shares which could be issued under both the PSOP and the share option plans, however, could not exceed 6.0 million common shares. Participants in the PSOP receive awards which, after three years, make them eligible to receive a set number of common shares or cash equivalent up to the maximum of the award amount plus any accrued dividends thereon. The actual number of common shares or cash equivalent a participant may receive is determined by the percentile ranking of the total shareholder return over three years of the corporation's common shares amongst the companies comprising the S&P/TSX Composite Index.

On Dec. 31, 2001, the plan was modified so that after three years, once the PSOP eligibility has been determined, 50 per cent of the shares may be released to the participant, while the remaining 50 per cent will be held in trust for one additional year. In addition, the number of common shares the corporation is authorized to grant under the terms of the PSOP was increased to 4.0 million common shares and the maximum number of common shares which may be issued under both the PSOP and share option plans was increased to 13.0 million common shares.

Year ended Dec. 31	**2006**	2005	2004
Number of awards outstanding, beginning of year	**1.1**	1.5	1.5
Granted	**0.6**	0.4	0.4
Awarded	**(0.1)**	(0.1)	–
Cancelled or expired	**(0.4)**	(0.7)	(0.4)
Number of awards outstanding, end of year	**1.2**	1.1	1.5

In 2006, PSOP compensation expense was $5.2 million (2005 – $10.6 million; 2004 – $3.4 million), which is included in OM&A expense in the statements of earnings. In 2006, 137,039 common shares were issued at $25.41 per share. In 2005, 65,332 common shares were issued at $25.41 per share. In 2004, 16,457 common shares were issued at $17.11 per share and 44,846 common shares were issued at $18.53 per share.

D. Employee Share Purchase Plan

Under the terms of the employee share purchase plan, the corporation will extend an interest-free loan (up to 30 per cent of an employee's base salary) to employees below executive level and allow for payroll deductions over a three-year period to repay the loan. Executives are no longer eligible for this program in accordance with the Sarbanes-Oxley legislation. The corporation will purchase these common shares on the open market on behalf of employees at prices based on the market price of the shares as determined on the date of purchase. Employee sales of these shares are handled in the same manner. At Dec. 31, 2006, accounts receivable from employees under the plan totalled $0.4 million (2005 – $0.6 million).

E. Stock-Based Compensation

At Dec. 31, 2006, the corporation had 2.2 million outstanding employee stock options (Dec. 31, 2005 – 2.9 million).

The corporation uses the fair value method of accounting for awards granted under its fixed stock option plans and its performance stock option plan. In March 2005, 1.2 million options were granted. One quarter of the options granted vest on each of the first, second, third and fourth anniversaries of the date of grant and expire after 10 years. The estimated fair value of these options granted was determined using the binomial model using the following assumptions, resulting in a fair value of $6.84 per option:

Risk-free interest rate	4.3%
Life of the options (years)	10
Dividend rate	5.6%
Volatility in the price of the corporation's shares	47.0%

The following table provides pro forma measures of net earnings and earnings per share had compensation expense been recognized based on the estimated fair value of the options on the grant date in accordance with the fair value method of accounting for stock-based compensation for grants made in 2002:

Year ended Dec. 31	2005	2004
Reported net earnings	$ 186.3	$ 169.2
Compensation expense	1.5	1.7
Pro forma net earnings	$ 184.8	$ 167.5
Reported basic earnings per share	$ 0.94	$ 0.88
Compensation expense per share	0.01	0.01
Pro forma basic earnings per share	$ 0.93	$ 0.87
Reported diluted earnings per share	$ 0.94	$ 0.88
Compensation expense per share	0.01	0.01
Pro forma diluted earnings per share	$ 0.93	$ 0.87

The estimated fair value of these stock options granted in 2002 and prior was determined using the binomial model using the following assumptions, resulting in a weighted-average fair value of $4.25:

Risk-free interest rate (%)	5.9
Expected hold period to exercise (years)	7.0
Volatility in the price of the corporation's shares (%)	28.3

26. EMPLOYEE FUTURE BENEFITS

A. Description

The corporation has registered pension plans in Canada and the U.S. covering substantially all employees of the corporation in these countries and specific named employees working internationally. These plans have defined benefit and defined contribution options, and in Canada, there is an additional supplemental defined benefit plan for Canadian-based defined contribution members whose annual earnings exceed the Canadian income tax limit. The defined benefit option of the registered pension plans has been closed for new employees for all periods presented.

The latest actuarial valuations of the registered and supplemental pension plans were as at Dec. 31, 2005. The measurement date used to determine plan assets and accrued benefit obligation was Dec. 31, 2006. The effective date of the next required valuation for funding purposes is Dec. 31, 2007. The supplemental pension plan is solely the obligation of the corporation. The corporation is not obligated to fund the supplemental plan but is obligated to pay benefits under the terms of the plan as they come due. The corporation has posted a letter of credit in the amount of $45.3 million to secure the obligations under the supplemental plan.

The corporation provides other health and dental benefits to the age of 65 for both disabled members (other post-employment benefits) and retired members (other post-retirement benefits). The latest actuarial valuation of these other plans was as at Dec. 31, 2004. The measurement date used to determine the accrued benefit obligation was also Dec. 31, 2006. The effective date of the next required valuation for funding purposes is Dec. 31, 2007.

B. Costs Recognized

Year ended Dec. 31, 2006	**Registered**	**Supplemental**	**Other**	**Total**
Current service cost	**$ 4.4**	**$ 1.2**	**$ 1.5**	**$ 7.1**
Interest cost	**19.7**	**2.0**	**1.1**	**22.8**
Actual return on plan assets	**(35.4)**	**–**	**–**	**(35.4)**
Actuarial (gains) losses in 2006	**(0.5)**	**1.0**	**(0.2)**	**0.3**
Difference between expected return and actual return on plan assets	**10.2**	**–**	**–**	**10.2**
Difference between actuarial (gain) loss recognized for the year and actual actuarial (gain) loss on accrued benefit obligation for the year	**3.1**	**–**	**0.5**	**3.6**
Difference between amortization of past service costs for the year and actual plan amendments for the year	**0.1**	**(0.2)**	**0.3**	**0.2**
Centralia mine closure charges	**1.4**	**–**	**–**	**1.4**
Amortization of net transition obligation (asset)	**(9.2)**	**0.3**	**–**	**(8.9)**
Defined benefit (income) cost	**(6.2)**	**4.3**	**3.2**	**1.3**
Defined contribution option expense of registered pension plan	**17.5**	**–**	**–**	**17.5**
Net expense	**$ 11.3**	**$ 4.3**	**$ 3.2**	**$ 18.8**

Year ended Dec. 31, 2005	Registered	Supplemental	Other	Total
Current service cost	$ 4.2	$ 1.1	$ 1.3	$ 6.6
Interest cost	20.4	2.0	1.2	23.6
Actual return on plan assets	(43.9)	–	–	(43.9)
Actuarial losses in 2005	26.3	4.6	0.9	31.8
Past service cost in 2005	0.5	(1.2)	–	(0.7)
Difference between expected return and actual return on plan assets	19.8	–	–	19.8
Difference between actuarial (gain) loss recognized for the year and actual actuarial (gain) loss on accrued benefit obligation for the year	(23.9)	(4.3)	(0.6)	(28.8)
Difference between amortization of past service costs for the year and actual plan amendments for the year	(0.4)	1.2	0.3	1.1
Amortization of net transition obligation (asset)	(9.2)	0.3	–	(8.9)
Defined benefit (income) cost	(6.2)	3.7	3.1	0.6
Defined contribution option expense of registered pension plan	16.1	–	–	16.1
Net expense	$ 9.9	$ 3.7	$ 3.1	$ 16.7

Year ended Dec. 31, 2004	Registered	Supplemental	Other	Total
Current service cost	$ 4.2	$ 1.1	$ 0.6	$ 5.9
Interest cost	20.5	2.1	1.0	23.6
Actual return on plan assets	(33.4)	–	–	(33.4)
Actuarial (gains) losses in 2004	14.4	(1.5)	0.2	13.1
Plan amendments in 2004	–	–	3.8	3.8
Difference between expected return and actual return on plan assets	9.6	–	–	9.6
Difference between actuarial (gain) loss recognized for the year and actual actuarial (gain) loss on accrued benefit obligation for the year	(12.3)	2.0	0.3	(10.0)
Difference between amortization of past service costs for the year and actual plan amendments for the year	0.1	(0.1)	(3.8)	(3.8)
Amortization of net transition obligation (asset)	(9.2)	0.3	–	(8.9)
Defined benefit (income) cost	(6.1)	3.9	2.1	(0.1)
Defined contribution option expense of registered pension plan	10.4	–	–	10.4
Net expense	$ 4.3	$ 3.9	$ 2.1	$ 10.3

In 2006, 2005 and 2004, the entire net expense related to continuing operations.

C. Status of Plans

Year ended Dec. 31, 2006	**Registered**	**Supplemental**	**Other**
Fair value of plan assets	**$ 374.3**	**$ 2.1**	**$ –**
Accrued benefit obligation	**398.6**	**43.6**	**23.5**
Funded status – plan deficit	**(24.3)**	**(41.5)**	**(23.5)**
Amounts not yet recognized in financial statements:			
Unrecognized past service costs	**0.8**	**(1.4)**	**3.2**
Unamortized transition (asset) obligation	**(36.6)**	**2.3**	**–**
Unamortized net actuarial gains	**46.3**	**10.7**	**5.5**
Total recognized in financial statements:			
Accrued benefit liability	**$ (13.8)**	**$ (29.9)**	**$ (14.8)**
Amortization period in years (EARSL)	**7**	**7**	**15**

Year ended Dec. 31, 2005	Registered	Supplemental	Other
Fair value of plan assets	$ 369.4	$ 1.7	$ –
Accrued benefit obligation	402.7	41.2	23.4
Funded status – plan deficit	(33.3)	(39.5)	(23.4)
Amounts not yet recognized in financial statements:			
Unrecognized past service costs	1.0	(1.6)	3.5
Unamortized transition (asset) obligation	(45.8)	2.6	–
Unamortized net actuarial gains	60.9	10.7	6.6
Total recognized in financial statements:			
Accrued benefit liability	$ (17.2)	$ (27.8)	$ (13.3)
Amortization period in years (EARSL)	8	8	15

The current portion of the accrued benefit liability is included in accounts payable and accrued liabilities on the consolidated balance sheets. The long-term portion is included in deferred credits and other long-term liabilities.

Year ended Dec. 31, 2006	**Registered**	**Supplemental**	**Other**
Accrued current liabilities	**$ –**	**$ 0.5**	**$ 1.5**
Other long-term liabilities	**13.8**	**29.4**	**13.3**
Accrued benefit liability	**$ 13.8**	**$ 29.9**	**$ 14.8**

Year ended Dec. 31, 2005	Registered	Supplemental	Other
Accrued current liabilities	$ 7.2	$ 0.5	$ 1.3
Other long-term liabilities	10.0	27.3	12.0
Accrued benefit liability	$ 17.2	$ 27.8	$ 13.3

D. Contributions

Expected cash flows are as follows:

		Registered		Supplemental		Other		Total
Employer contributions								
2007 (expected)	$	4.8	$	0.5	$	0.6	$	5.9
Expected benefit payments								
2007		24.2		2.0		1.5		27.7
2008		24.7		2.0		1.5		28.2
2009		25.6		2.1		1.6		29.3
2010		26.1		2.3		1.7		30.1
2011		26.8		2.4		1.9		31.1
2012 – 2016		141.6		13.3		10.5		165.4

E. Plan Assets

		Registered		Supplemental		Other
Fair value of plan assets at Dec. 31, 2004	$	352.0	$	1.3	$	–
Contributions		2.1		0.5		0.3
Transfers		0.1		–		–
Benefits paid		(27.7)		(0.1)		(0.3)
Effect of translation on U.S. plans		(1.0)		–		–
Actual return on plan assets [1]		43.9		–		–
Fair value of plan assets at Dec. 31, 2005	$	369.4	$	1.7	$	–
Contributions		3.8		0.5		0.3
Transfers		(6.4)		–		–
Benefits paid		(27.6)		(0.1)		(0.3)
Effect of translation on U.S. plans		(0.4)		–		–
Actual return on plan assets [1]		35.5		–		–
Fair value of plan assets at Dec. 31, 2006	**$**	**374.3**	**$**	**2.1**	**$**	**–**

1 *Net of expenses.*

The corporation's investment policy is to achieve a consistently high investment return over time while maintaining an acceptable level of risk to satisfy the benefit obligations of the pension plans. The goal is to maintain a long-term rate of return on the fund that at least equals the growth of liabilities, currently seven per cent. The pension fund may be invested in publicly traded common or preferred equity shares, rights or warrants; convertible debentures or preferred securities; bonds, debentures, mortgages, notes or other debt instruments of government agencies or corporations; private company securities; guaranteed investment contracts; term deposits; cash or money market securities; and mutual or pooled funds eligible for pension fund investment. The target allocation percentages are 60 per cent equity and 40 per cent fixed income. Cash and money market instruments may be held from time-to-time as short-term investment decisions or as defensive reserves within the portfolios of each asset class. The fund may invest in derivatives for the purpose of hedging the portfolio or altering the desired mix of the fund. Derivative transactions that leverage the fund in any way are not permitted without the specific approval of the corporation's pension committee.

The allocation of plan assets by major asset category at Dec. 31, 2006 and 2005 is as follows:

Year ended Dec. 31, 2006	**Registered**	**Supplemental**
Equity securities	**62.3%**	**–**
Debt securities	**37.4%**	**–**
Cash equivalents	**0.3%**	**100.0%**
Total	**100.0%**	**100.0%**

Year ended Dec. 31, 2005	Registered	Supplemental
Equity securities	62.8%	–
Debt securities	36.7%	–
Cash equivalents	0.5%	100.0%
Total	100.0%	100.0%

Plan assets include common shares of the corporation having a fair value of $1.1 million at Dec. 31, 2006 (2005 – $1.0 million). The corporation charged the registered plan $0.1 million for administrative services provided for the year ended Dec. 31, 2006 (2005 – $0.1 million).

F. Reconciliation of Accrued Benefit Obligations

	Registered	Supplemental	Other
Accrued benefit obligation as at Dec. 31, 2004	$ 379.0	$ 36.5	$ 21.7
Current service cost	4.2	1.1	1.3
Interest cost	20.4	2.0	1.2
Expected benefits paid	(25.7)	(1.8)	(1.2)
Past service cost	0.5	(1.2)	–
Effect of translation on U.S. plans	(2.0)	–	(0.5)
Actuarial loss	26.3	4.6	0.9
Accrued benefit obligation as at Dec. 31, 2005	$ 402.7	$ 41.2	$ 23.4
Current service cost	4.3	1.2	1.5
Interest cost	19.7	2.1	1.2
Expected benefits paid	(25.9)	(1.8)	(1.2)
Past service cost	–	–	–
Effect of translation on U.S. plans	(0.7)	–	(0.2)
Actuarial gain (loss)	(1.5)	0.9	(1.2)
Accrued benefit obligation as at Dec. 31, 2006	**$ 398.6**	**$ 43.6**	**$ 23.5**

G. Assumptions

The significant actuarial assumptions adopted in measuring the corporation's accrued benefit obligations were as follows:

Year ended Dec. 31, 2006	**Registered**	**Supplemental**	**Other**
Accrued benefit obligation at Dec. 31			
Discount rate	**5.1%**	**5.0%**	**5.3%**
Rate of compensation increase	**3.8%**	**3.8%**	**–**
Benefit cost for year ended Dec. 31			
Discount rate	**5.0%**	**5.0%**	**5.2%**
Rate of compensation increase	**3.5%**	**3.5%**	**–**
Expected rate of return on plan assets	**7.1%**	**–**	**–**
Assumed health care cost trend rate at Dec. 31			
Health care cost escalation	**–**	**–**	**9.0%–9.5%**[1]
Dental care cost escalation	**–**	**–**	**4.0%**
Provincial health care premium escalation	**–**	**–**	**2.5%**

Year ended Dec. 31, 2005	Registered	Supplemental	Other
Accrued benefit obligation at Dec. 31			
Discount rate	5.0%	5.0%	5.2%
Rate of compensation increase	3.5%	3.5%	–
Benefit cost for year ended Dec. 31			
Discount rate	5.5%	5.5%	5.6%
Rate of compensation increase	3.5%	3.5%	–
Expected rate of return on plan assets	7.1%	–	–
Assumed health care cost trend rate at Dec. 31			
Health care cost escalation	–	–	9.5%–11.5%[1]
Dental care cost escalation	–	–	4.0%
Provincial health care premium escalation	–	–	2.5%

1 *Decreasing gradually to 5.0 per cent by 2015 for Canadian plans and by 2012 for U.S. plans and remaining at that level thereafter.*

The expected long-term rate of return on plan assets is based on past performance and economic forecasts for the types of investments held by the plan. The estimated rate of return is lower than the historical returns of the appropriate indices.

Sensitivity to changes in assumed health care cost trend rates are as follows:

	One percentage point increase	One percentage point decrease
Effect on total service and interest costs	$ 0.3	$ (0.2)
Effect on post-retirement benefit obligation	$ 1.4	$ (1.3)

27. JOINT VENTURES

Joint ventures at Dec. 31, 2006 included the following:

Joint venture	Ownership interest	Description
Sheerness joint venture	50%	Coal-fired plant in Alberta, of which TA Cogen has a 50 per cent interest, and is operated by Canadian Utilities
Meridian joint venture	50%	Cogeneration plant in Alberta, of which TA Cogen has a 50 per cent interest, and is operated by TransAlta
Fort Saskatchewan joint venture	60%	Cogeneration plant in Alberta, of which TA Cogen has a 60 per cent interest, and is operated by TransAlta
McBride Lake joint venture	50%	Wind generation facilities in Alberta, operated by TransAlta
Goldfields Power joint venture	50%	Gas-fired plant in Australia, operated by TransAlta
CE Generation LLC	50%	Geothermal and gas plants in the United States, operated by CE Gen affiliates
Genesee 3	50%	Coal-fired plant in Alberta, operated by EPCOR Utilities Inc.
Wailuku	50%	A run-of-river generation facility in Hawaii, operated by MidAmerican Holdings Ltd.

Summarized information on the results of operations, financial position and cash flows relating to the corporation's pro-rata interests in its jointly controlled corporations was as follows:

	2006	2005	2004
Results of operations			
Revenues	**$ 608.2**	$ 619.9	$ 505.2
Expenses	**(455.3)**	(481.1)	(424.3)
Non-controlling interests	**(41.9)**	(43.7)	(37.1)
Proportionate share of net earnings	**$ 111.0**	$ 95.1	$ 43.8
Cash flows			
Cash flow from operations	**$ 112.8**	$ 111.5	$ 153.2
Cash flow used in investing activities	**(30.7)**	(10.3)	(21.6)
Cash flow used in financing activities	**(63.2)**	(76.3)	(129.1)
Proportionate share of decrease in cash and cash equivalents	**$ 18.9**	$ 24.9	$ 2.5
Financial position			
Current assets	**$ 146.3**	$ 162.5	$ 112.7
Long-term assets	**1,797.9**	1,895.4	2,033.7
Current liabilities	**(115.4)**	(118.0)	(110.9)
Long-term liabilities	**(489.7)**	(552.7)	(635.6)
Non-controlling interests	**(376.3)**	(396.1)	(416.3)
Proportionate share of net assets	**$ 962.8**	$ 991.1	$ 983.6

28. SUBSEQUENT EVENTS

On Feb. 14, 2007, the Alberta Energy and Utilities Board approved the development of the 450 MW Keephills 3 coal-fired power plant. The plant will be developed jointly by EPCOR and TransAlta. On Feb. 26, 2007, TransAlta and EPCOR announced that they will proceed with building the Keephills 3 project. The capital cost of the project is expected to be approximately $1.6 billion.

On Jan. 19, 2007, the corporation announced that it had been awarded a 25-year long-term contract to provide 75 MW of wind power to New Brunswick Power Distribution and Customer Service Corporation. TransAlta will construct, own and operate a wind power facility in New Brunswick. The cost of the project is estimated to be $130 million. The co-development partner for this project is Natural Forces Technologies Inc. with commercial operations expected to begin at the end of 2008.

On Jan. 2, 2007, the corporation redeemed Preferred Securities that had an aggregate principal of $175.0 million.

29. COMPARATIVE FIGURES

Certain of the comparative figures have been reclassified to conform with the current year's presentation. Such reclassification did not impact previously reported net income or retained earnings.

30. UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

These consolidated financial statements have been prepared in accordance with Canadian GAAP, which, in most respects, conform to U.S. GAAP. Significant differences between Canadian and U.S. GAAP are as follows:

A. Earnings and Earnings Per Share (EPS)

Year ended Dec. 31	Reconciling items	2006	2005 (Restated, Note 1)	2004 (Restated, Note 1)
Earnings from continuing operations – Canadian GAAP		$ 44.9	$ 174.3	$ 159.6
Derivatives and hedging activities, net of tax	I	–	10.5	(3.8)
Start-up costs, net of tax	III	(0.1)	(0.1)	(0.1)
Amortization of pension transition adjustment	II	(4.4)	(4.0)	(4.5)
Earnings from continuing operations – U.S. GAAP		40.4	180.7	151.2
Earnings from discontinued operations, net of tax – Canadian and U.S. GAAP		–	12.0	9.6
Net earnings before change in accounting principle – U.S. GAAP		40.4	192.7	160.8
Cumulative effect of change in accounting principle – employee future benefits, net of tax	II	(40.7)	–	–
Net earnings – U.S. GAAP		$ (0.3)	$ 192.7	$ 160.8
Foreign currency cumulative translation adjustment	I,VII	(4.8)	(22.6)	3.7
Net gain (loss) on derivative instruments	I,VII	80.5	(214.6)	10.4
Registered pension alternate minimum liability	V,VII	13.2	(11.5)	(0.6)
Comprehensive income – U.S. GAAP		$ 88.6	$ (56.0)	$ 174.3
Basic and diluted EPS – U.S. GAAP				
Earnings from continuing operations		$ 0.20	$ 0.92	$ 0.78
Earnings from discontinued operations		–	0.06	0.05
Cumulative effect of change in accounting principle – employee future benefits		(0.20)	–	–
Net earnings		$ –	$ 0.98	$ 0.83

B. Balance Sheet Information

As at Dec. 31	Reconciling items	2006 Canadian GAAP	2006 U.S. GAAP	2005 Canadian GAAP	2005 U.S. GAAP (Restated, Note 1)
ASSETS					
Price risk management assets, current	I	$ 61.0	$ 99.1	$ 63.8	$ 77.7
Income taxes receivable	I	47.6	48.8	48.8	50.2
Property, plant and equipment, net	III	5,041.9	5,038.7	5,551.5	5,548.4
Price risk management assets, long-term	I	21.9	133.3	13.8	162.6
Other assets (including current portion)	I, II, III	148.0	34.2	211.0	46.3
LIABILITIES					
Accounts payable and accrued liabilities	V	441.9	432.6	590.3	587.5
Income taxes payable	III	22.3	16.9	13.8	8.4
Price risk management liabilities, current	I	30.3	122.6	58.3	229.7
Long-term debt	I	1,971.1	1,976.5	2,208.6	2,237.0
Deferred credits and other liabilities (including current portion)	I, XI	474.0	508.0	365.9	365.9
Price risk management liabilities, long-term	I	1.0	283.8	8.6	259.3
Future or deferred income tax liabilities (including current portion)	I, II, III	718.5	606.0	757.0	608.4
Non-controlling interests	I	535.0	534.3	558.6	557.9
EQUITY					
Contributed surplus	IV	–	133.0	–	133.0
Retained earnings	I, II, III	710.0	552.7	866.1	710.7
Cumulative translation adjustment	I	(64.5)	–	(67.0)	–
Accumulated other comprehensive loss	I, III, VII	–	(293.1)	–	(341.3)

I. Derivatives and Hedging Activities

Under U.S. GAAP, trading and non-trading activities are accounted for in accordance with Statement 133, which requires that derivative instruments be recorded in the consolidated balance sheets at fair value as either assets or liabilities, and that changes in fair value be recognized currently in earnings, unless specific hedge accounting criteria are met. If the derivative is designated as a fair value hedge, the changes in the fair value of the derivative and of the hedged item attributable to the hedged risk are recognized currently in earnings. If the derivative is designated as a cash flow hedge, the changes in the fair value of the derivative are recorded in other comprehensive income, and the gains and losses related to these derivatives are recognized in earnings in the same period as the settlement of the underlying hedged transaction. Any ineffectiveness relating to these hedges is recognized currently in earnings. The assets and liabilities related to derivative instruments for which hedge accounting criteria are met are reflected as price risk management assets and liabilities in the consolidated balance sheets. Many of the corporation's electricity sales and fuel supply agreements that otherwise would be required to follow derivative accounting qualify as normal purchases and normal sales under Statement 133 and are therefore exempt from fair value accounting treatment. This exemption is available for the electricity industry as electricity cannot be stored and generators may be required to maintain sufficient capacity to meet customer demands. This exemption is also available for some physically settled commodity contracts if certain criteria are met. Non-derivatives used in trading activities are accounted for using the accrual method under U.S. GAAP.

i. Fair Value Hedging Strategy

The corporation enters into forward exchange contracts to hedge certain firm commitments denominated in foreign currencies to protect against adverse changes in exchange rates and uses interest rate swaps to manage interest rate exposure. The swaps modify exposure to interest rate risk by converting a portion of the corporation's fixed-rate debt to a floating rate.

There was no ineffectiveness related to these hedges in the periods presented.

ii. Cash Flow Hedging Strategy

At Dec. 31, 2006, the corporation's cash flow hedges of the forecasted sale of power and the forecasted purchase of natural gas for the corporation's plants resulted in the recognition of an after-tax unrealized gain in Other Comprehensive Income (OCI) of $71.0 million (2005 – $241.7 million loss; 2004 – $3.7 million loss). These hedges have been accounted for on an accrual basis under Canadian GAAP but have been recorded on the balance sheet at fair value for U.S. GAAP.

For the years ending Dec. 31, 2006, 2005 and 2004, the corporation's cash flow hedges resulted in no after-tax gain or loss on either designated or ineffective portions.

Over the next 12 months, the corporation estimates that $80.5 million of after-tax losses that arose from cash flow hedges from prior years will be reclassified from Accumulated Other Comprehensive Income (AOCI) to net earnings. These estimates assume constant gas and power prices, interest rates and exchange rates over time; however, the actual amounts that will be reclassified will vary based on changes in these factors. Therefore, management is unable to predict what the actual reclassification from AOCI to earnings, either positive or negative, will be for the next 12 months.

iii. Net Investment Hedges

The company uses cross-currency interest rate swaps, forward sales contracts and direct foreign currency debt to hedge its exposure to changes in the carrying value of its investments in its foreign subsidiaries in the U.S., Australia and Mexico. Realized and unrealized gains and losses from these hedges are included in OCI, with the related amounts due to or from counterparties included in long-term derivative assets and liabilities and long-term debt.

In the year ended Dec. 31, 2006, the corporation recognized an after-tax loss of $4.8 million (2005 – $22.6 million loss; 2004 – $3.7 million income) on its net investment hedges, included in OCI.

For the years ending Dec. 31, 2006, 2005 and 2004 the corporation recognized no after-tax gains or losses related to ineffectiveness of net investment hedges.

iv. Trading Activities

The corporation markets energy derivatives to optimize returns from assets, to earn trading revenues and to gain market information. Derivatives, as defined under Statement 133, are recorded on the consolidated balance sheets at fair value under both Canadian and U.S. GAAP. Non-derivative contracts entered into subsequent to the rescission of EITF 98-10 are accounted for using the accrual method.

v. Other Hedging Activities

In the year ended Dec. 31, 2006, the corporation recognized pre-tax losses of $nil (2005 – $13.7 million; 2004 – $1.1 million) related to hedging activities that do not qualify for hedge accounting under Statement 133.

II. Employee Future Benefits

U.S. GAAP requires that the cost of employee pension benefits be determined using the accrual method with application from 1989. It was not feasible to apply this standard using this effective date. The transition asset as at Jan. 1, 1998 was determined in accordance with elected practice prescribed by the SEC and is amortized over 10 years.

As a result of the corporation's plan asset return experience for its U.S. registered pension plan at Dec. 31, 2005, the corporation was required under U.S. GAAP to recognize an additional minimum liability. The liability was recorded as a reduction in common equity through a charge to OCI, and did not affect net income for 2005. The charge to OCI, will be restored through common equity in future periods to the extent the fair value of trust assets exceeds the accumulated benefit obligation.

Cumulative Effect of Change in Accounting Principle

In September 2006, the FASB issued Statement of Financial Accounting Standards (SFAS) No. 158 (SFAS 158), *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans* – an amendment of FASB Statements No. 87, 88, 106, and 132(R). SFAS 158 requires companies to report the funded status of their defined benefit pension plans on the balance sheet with changes in the funded status recognized in other comprehensive income in the year of the change. SFAS 158 also requires additional disclosure. SFAS 158 is effective for years ending after Dec. 15, 2006. TransAlta has complied with the requirements of SFAS 158. The following chart outlines the deficiency of assets over projected benefit obligation (PBO).

	Registered plan	Supplemental plan	Other	Total
Market value of plan assets	$ 374.3	$ 2.1	$ –	$ 376.4
Projected benefit obligation	398.6	43.6	23.5	465.7
Deficiency of assets over PBO	$ (24.3)	$ (41.5)	$ (23.5)	$ (89.3)

The adjustments as a result of adopting this standard are outlined below:

Changes in shareholders' equity	Other comprehensive income	Accumulated other comprehensive income
Retirement Plan		
Balance as at Dec. 31, 2005	$ –	$ (13.2)
Decrease in additional liability included in OCI	13.2	13.2
Adjustment to adopt SFAS 158	–	(40.7)
Balance as at Dec. 31, 2006	**$ –**	**$ (40.7)**

III. Start-Up Costs

Under U.S. GAAP, certain start-up costs, including revenues and expenses in the pre-operating period, are expensed rather than capitalized to deferred charges and property, plant and equipment as under Canadian GAAP, which also results in decreased depreciation and amortization expense under U.S. GAAP.

IV. Debt Extinguishment

Under U.S. GAAP, the premium on redemption of long-term debt related to the 1998 limited partnership transaction was recorded when incurred, whereas for Canadian GAAP, the loss was being amortized to earnings over the period of the limited partnership (20 years). As the buyback option was terminated in connection with the sale of the Sheerness plant, the deferred amount was recognized in earnings in 2003.

V. Income Taxes

Future income taxes under Canadian GAAP are referred to as deferred income taxes under U.S. GAAP.

Deferred income taxes under U.S. GAAP would be as follows:

As at Dec. 31	**2006**	2005
		(Restated, Note 1)
Future income tax liabilities (net) under Canadian GAAP	**$ (398.7)**	$ (560.3)
Derivatives	**121.6**	160.0
Start-up costs	**(2.3)**	(2.3)
Pensions	**(6.8)**	(9.1)
	$ (286.2)	$ (411.7)

Comprised of the following:

As at Dec. 31	2006	2005
		(Restated, Note 1)
Current deferred income tax assets	**$ 25.8**	$ 26.6
Long-term deferred income tax assets	**294.0**	170.1
Current deferred income tax liabilities	**(19.9)**	(15.5)
Long-term deferred income tax liabilities	**(586.1)**	(592.9)
	$ (286.2)	$ (411.7)

VI. Joint Ventures

In accordance with Canadian GAAP, joint ventures are required to be proportionately consolidated regardless of the legal form of the entity. Under U.S. GAAP, incorporated joint ventures are required to be accounted for by the equity method. However, in accordance with practices prescribed by the SEC, the corporation, as a Foreign Private Issuer, has elected to disclose the amounts proportionately consolidated in *Note 27*.

VII. Other Comprehensive Income (Loss)

The changes in the components of OCI were as follows:

Year ended Dec. 31	2006	2005	2004
Net gain on derivative instruments:			
Unrealized gain (loss), net of taxes of $52.3 million	**$ 80.5**	$ (204.4)	$ 7.0
Reclassification adjustment for losses included in net income	**–**	(10.2)	3.4
Net gain (loss) on derivative instruments	**80.5**	(214.6)	10.4
Translation adjustments	**(4.8)**	(22.6)	3.7
Change in accounting principle – employee future benefits	**(40.7)**	–	–
Registered pension alternate minimum liability (net of taxes)	**13.2**	(11.5)	(0.6)
Other comprehensive (loss) income	**$ 48.2**	$ (248.7)	$ 13.5

The components of AOCI were:

Year ended Dec. 31	2006	2005	2004
Net loss on derivative instruments	**$ (194.9)**	$ (275.4)	$ (60.8)
Translation adjustments	**(57.5)**	(52.7)	(30.1)
Change in accounting principle – employee future benefits	**(40.7)**	–	–
Registered pension alternate minimum liabilities	**–**	(13.2)	(1.7)
Accumulated other comprehensive loss	**$ (293.1)**	$ (341.3)	$ (92.6)

VIII. Asset Retirement Obligations

FASB issued Statement 143, Asset Retirement Obligations, which requires asset retirement obligations to be measured at fair value and recognized when the obligation is incurred. A corresponding amount is capitalized as part of the asset's carrying amount and depreciated over the asset's useful life. TransAlta adopted the provisions of Statement 143 effective Jan. 1, 2003.

In accordance with Canadian GAAP, the asset retirement obligations standard was adopted retroactively with restatement of prior periods. Under U.S. GAAP, the impact of adopting Statement 143 was recognized as a cumulative effect of a change in accounting principle as of Jan. 1, 2003, the beginning of the fiscal year in which the Statement was first applied. The change resulted in an after-tax increase in net earnings of $52.5 million ($82.7 million pre-tax).

In March 2005, the FASB issued FASB Interpretation (FIN) No. 47, *Accounting for Conditional Asset Retirement Obligations, an Interpretation of FASB Statement No. 143*. FIN No. 47 clarifies the term conditional asset retirement obligation as used in SFAS No. 143, *Accounting for Asset Retirement Obligations*, and provides further guidance as to when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation.

The adoption of FIN No. 47 on Dec. 31, 2005 did not result in any impact to TransAlta's results of operations or financial position for the year ended Dec. 31, 2005.

IX. Limited Partnership Transaction

In 1998, the corporation transferred generation assets to its subsidiary TA Cogen. TA Power, an unrelated entity, concurrently subscribed to a minority interest in TA Cogen. The fair value paid by TA Cogen for the assets exceeded their historical carrying values. For Canadian GAAP, the corporation recognized a portion of this difference, to the extent it was funded by TA Power's investment in TA Cogen, as a gain. As TA Power held an option to resell its interest in TA Cogen to the corporation in 2018, TA Power's option to resell these units was eliminated and the unamortized balance of the gain was recognized in income.

Under U.S. Securities and Exchange Commission Staff Accounting Bulletin No. 51, the option initially held by TA Power to potentially resell TA Cogen units to the corporation in 2018 causes the excess of the consideration paid by TA Power over the corporation's historical carrying value in these assets to be characterized as contributed surplus in 1998. This amount of contributed surplus is reduced by the related tax effect. As a result, under U.S. GAAP, there is no amortization of the gain into income in the period from 1998 to 2002 and no recognition of the unamortized balance of the gain in 2003.

X. Restatement

During the third quarter of 2005, the corporation determined, as described in footnote IX above, that the gain recognized under Canadian GAAP arising from 1998 transactions involving TA Cogen and TA Power is a capital transaction under U.S. GAAP. The corporation has retroactively corrected its reconciliation to U.S. GAAP. The impact of this adjustment on amounts previously reported under U.S. GAAP is as follows:

(millions of dollars except per share amounts)		2004
Decrease in:		
Earnings from continuing operations	$	–
Net earnings	$	–
Net earnings per share in accordance with U.S. GAAP		
Continuing operations	$	–
Discontinued operations	$	–
Basic	$	–
Diluted	$	–

The impact on previously reported balance sheet amounts for U.S. GAAP purposes is as follows:

(in millions of dollars)		2004
Increase (decrease) in:		
Contributed surplus	$	133.0
Retained earnings	$	(133.0)

XI. Changes in Accounting Standards

In June 2006, the Emerging Issues Task Force (EITF) issued EITF Issue No. 06-2 *Accounting for Sabbatical Leave and Other Similar Benefits* Pursuant to FASB Statement No. 43, *Accounting for Compensated Absences* (Issue No. 06-2). Under Issue No. 06-2 a company should accrue for sabbatical leave or other similar benefits if (i) the employee is required to complete a minimum service period to be entitled to the benefit, (ii) there is no increase to the benefit if the employee provides additional years of service, (iii) the employee continues to be a compensated employee during his or her absence and (iv) the employer does not require the employee to perform any duties during his or her absence. Issue No. 06-2 is effective for fiscal years beginning after Dec. 15, 2006. TransAlta has evaluated the accounting guidance and has adopted the consensus effective Jan. 1, 2007. The adoption does not have a material impact upon the corporation's financial statements.

In July 2006, the FASB issued Interpretation No. 48, *Accounting for Uncertainty in Income Taxes, an Interpretation of FASB Statement No. 109* (FIN 48). FIN 48 is intended to provide a single model to address accounting for uncertain tax positions by establishing a recognition threshold and measurement for tax positions taken or expected to be taken in a tax return. Further, clarification on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition is also provided. The guidance in FIN 48 is effective for fiscal years beginning after Dec. 31, 2006. The corporation will adopt FIN 48 as of Jan. 1, 2007, as required. The corporation is currently assessing the impact of the adoption of FIN 48.

ELEVEN-YEAR FINANCIAL & STATISTICAL SUMMARY

Year ended Dec. 31	2006	2005	2004	2003
(in millions of Canadian dollars, except where noted)				
FINANCIAL SUMMARY				
Earnings statement				
Revenues	**$ 2,796.5**	$ 2,838.5	$ 2,838.3	$ 2,508.6
Operating income	**$ 156.6**	$ 441.2	$ 478.1	$ 553.7
Net earnings applicable to common shareholders	**$ 44.9**	$ 198.8	$ 170.2	$ 234.2
Balance sheet				
Total assets	**$ 7,460.1**	$ 7,740.7	$ 8,133.0	$ 8,420.2
Short-term debt, net of cash and interest-earning investments	**$ 296.3**	$ (66.2)	$ (102.7)	$ (35.2)
Long-term debt	**$ 2,220.8**	$ 2,605.0	$ 3,057.9	$ 3,162.1
Preferred shares of a subsidiary	**$ –**	$ –	$ –	$ –
Other non-controlling interests	**$ 535.0**	$ 558.6	$ 616.4	$ 477.9
Preferred securities	**$ 175.0**	$ 175.0	$ 175.0	$ 450.8
Common shareholders' equity	**$ 2,427.9**	$ 2,543.1	$ 2,472.7	$ 2,460.6
Total invested capital	**$ 5,307.2**	$ 5,809.2	$ 6,519.3	$ 6,516.2
Cash flow				
Cash flow from operating activities	**$ 489.6**	$ 619.4	$ 613.4	$ 756.5
Cash flow used in investing activities	**$ 261.3**	$ (242.1)	$ (65.4)	$ (535.1)
Common share information (per share)				
Net earnings	**$ 0.22**	$ 1.01	$ 0.88	$ 1.26
Dividends declared	**$ 1.00**	$ 1.00	$ 1.00	$ 1.00
Book value (at year-end)	**$ 11.99**	$ 12.80	$ 12.74	$ 12.90
Market price:				
High	**$ 26.91**	$ 26.66	$ 18.75	$ 19.55
Low	**$ 20.22**	$ 17.67	$ 15.25	$ 15.36
Close (TSX at Dec. 31)	**$ 26.64**	$ 25.41	$ 18.05	$ 18.53
Ratios (percentage except where noted)				
Debt/invested capital	**40.9**	43.6	47.4	47.9
Return on common shareholders' equity	**1.8**	7.5	6.5	10.3
Return on invested capital	**2.5**	7.4	7.5	9.1
Cash flow to total debt	**26.2**	23.5	18.5	17.9
Cash flow to interest coverage (times)	**5.5**	4.8	4.1	3.3
Dividend payout	**447.7**	105.4	120.0	79.0
Dividend yield	**3.8**	3.9	5.5	5.4
Price/earnings multiple (times)	**121.1**	26.7	21.7	14.7
Weighted average common shares for the year (in millions)	**200.8**	196.8	192.7	185.3
Common shares outstanding at Dec. 31 (in millions)	**202.4**	198.7	194.1	190.7
STATISTICAL SUMMARY				
Number of employees	**2,687**	2,657	2,505	2,563
Generating capacity (net MW) [3]:				
Hydro	**807**	802	802	801
Coal	**4,887**	4,885	4,778	4,777
Gas	**1,953**	1,933	2,444	2,499
Renewables	**315**	315	313	245
Total generating capacity	**7,962**	7,935	8,337	8,322
Total generation production (GWh) [4]	**48,213**	51,810	54,560	53,134

* **Prior years have not been restated to conform with the current year's presentation.**

1 *2002 and 2001 Energy Marketing real-time trading contract revenues restated to be presented on a gross basis.*

2 *Includes discontinued operations.*

3 *Represents TransAlta's ownership.*

4 *Includes discontinued operations.*

Ratio Formulas

Debt/invested capital = (short-term debt + long-term debt – cash and interest-earning investments)/(debt + preferred securities + non-controlling interests + common equity)

Return on common shareholders' equity = net earnings excluding gain on discontinued operations/average of opening and closing common equity

2002	2001	2000	1999	1998	1997	1996
$ 1,814.9[1]	$ 2,559.5[1]	$ 1,587.0	$ 1,029.4	$ 1,089.9	$ 1,656.4	$ 1,515.6
$ 223.9[2]	$ 468.9[2]	$ 604.6[2]	$ 442.0[2]	$ 660.1[2]	$ 586.6	$ 570.6
$ 189.9	$ 214.6	$ 279.8	$ 170.1	$ 211.4	$ 182.6	$ 181.0
$ 7,419.6	$ 7,877.9	$ 7,627.1	$ 6,038.4	$ 5,392.6	$ 4,882.2	$ 4,804.4
$ 146.7	$ 475.2	$ 220.5	$ (173.6)	$ (149.4)	$ (20.3)	$ 13.3
$ 2,706.6	$ 2,511.1	$ 2,201.4	$ 2,177.4	$ 1,903.6	$ 2,198.0	$ 2,364.0
$ –	$ –	$ 121.6	$ 268.3	$ 268.4	$ 267.6	$ 270.5
$ 263.0	$ 281.0	$ 253.4	$ 377.4	$ 503.3	$ 162.9	$ 164.4
$ 451.7	$ 452.6	$ 292.0	$ 287.1	$ –	$ –	$ –
$ 2,039.6	$ 1,989.7	$ 1,957.4	$ 1,835.6	$ 1,855.0	$ 1,594.3	$ 1,582.3
$ 5,607.6	$ 5,709.6	$ 5,046.3	$ 4,772.2	$ 4,380.9	$ 4,202.5	$ 4,394.5
$ 437.7	$ 715.6	$ 188.7	$ 422.0	$ 470.7	$ 666.4	$ 563.2
$ (36.2)	$ (1,076.9)	$ (205.0)	$ (988.8)	$ (137.2)	$ (319.7)	$ (459.9)
$ 1.12	$ 1.27	$ 1.66	$ 1.00	$ 1.31	$ 1.14	$ 1.14
$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 0.99	$ 0.98	$ 0.98
$ 12.01	$ 11.82	$ 11.61	$ 10.85	$ 10.94	$ 9.96	$ 9.92
$ 23.95	$ 30.13	$ 22.55	$ 25.15	$ 25.40	$ 22.75	$ 18.20
$ 16.69	$ 19.15	$ 13.20	$ 12.25	$ 18.20	$ 15.10	$ 14.25
$ 17.11	$ 21.60	$ 22.00	$ 14.15	$ 22.60	$ 22.55	$ 17.25
50.9	52.3	48.0	45.6	40.0	51.8	54.1
3.5	10.9	11.7	9.2	12.3	11.5	11.6
4.0	8.7	12.3	9.7	15.4	13.7	13.6
16.1	21.8	25.3	21.7	22.8	22.0	22.1
3.8	–	–	–	–	–	–
241.8	78.5	75.8	99.7	75.8	85.7	86.2
5.8	4.6	4.6	7.1	4.4	4.4	5.7
41.7	17.3	16.7	14.2	17.3	19.8	15.1
169.6	169.0	168.8	169.5	161.3	159.7	159.2
169.8	168.3	168.6	169.2	169.6	160.0	159.5
2,573	2,656	2,363	2,679	2,455	2,667	3,099
801	800	800	800	800	800	800
4,966	5,090	5,016	3,676	3,676	3,676	3,676
1,333	1,108	1,054	1,464	1,008	832	815
44	–	–	–	–	–	–
7,144	6,998	6,870	5,940	5,484	5,308	5,291
46,877	44,136	40,644	37,771	39,001	36,401	34,264

Return on invested capital = earnings before non-controlling interests, income taxes and net interest expense/average annual invested capital

Cash flow to total debt = cash flow from operations before changes in working capital/two-year average of total debt

Dividend payout = dividends/net earnings excluding gain on discontinued operations

Dividend yield = common share dividends/current year's close price

Price/earnings multiple = current year's close/basic earnings per share from continuing operations

SHAREHOLDER INFORMATION

ANNUAL MEETING

The Annual meeting will be held at 11:00 a.m. MST on Thursday, April 26, 2007 at the Calgary Zoo, Safari Lodge Canada Room, 1300 Zoo Road N.E., Calgary, Alberta.

TRANSFER AGENT

CIBC Mellon Trust Company
P.O. Box 7010
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Toronto, Ontario M5C 2W9

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EXCHANGES

Toronto Stock Exchange (TSX)
New York Stock Exchange (NYSE)

TICKER SYMBOLS

TransAlta Corporation common shares:
TSX: TA NYSE: TAC

VOTING RIGHTS

Common shareholders receive one vote for each common share held

ADDITIONAL INFORMATION

Requests can be directed to:
Investor Relations
TransAlta Corporation
P.O. Box 1900, Station "M"
110 - 12th Avenue S.W.
Calgary, Alberta T2P 2M1

Phone
North America:
1.800.387.3598 toll-free
Calgary/outside North America:
403.267.2520

E-mail
investor_relations@transalta.com

Fax
403.267.2590

Website
www.transalta.com

SPECIAL SERVICES FOR REGISTERED SHAREHOLDERS

Service	Description
Dividend reinvestment and share purchase plan*	Conveniently reinvest your TransAlta dividends and purchase common shares without brokerage costs
Direct deposit for dividend payments	Automatically have dividend payments deposited to your bank account
Account consolidations	Eliminate costly duplicate mailings by consolidating account registrations
Address changes and share transfers	Receive tax slips and dividends without the delays resulting from address and ownership changes

To use these services please contact our transfer agent.

* *Also available to non-registered shareholders.*

STOCK SPLITS AND SHARE CONSOLIDATIONS

Date	Events	Ratio
May 8, 1980	Stock split	3:1
Feb. 1, 1988	Stock split [1]	2:1
Dec. 31, 1992	Reorganization – TransAlta Utilities shares exchanged for TransAlta Corporation shares [2]	1:1

The valuation date value of common shares owned on Dec. 31, 1971, adjusted for stock splits, is $4.54 per share.

1 *The adjusted cost base for shares held on Jan. 31, 1988 was reduced by $0.75 per share following the Feb. 1, 1988 share split.*

2 *TransAlta Utilities Corporation became a wholly-owned subsidiary of TransAlta Corporation as a result of this reorganization.*

DIVIDEND DECLARATION

In declaring dividends, the directors consider several factors, including the corporation's earnings, cash flow, capital requirements and the expectations of shareholders.

IMPORTANT DIVIDEND DATES

Payment Date	Record Date	Ex-Dividend Date
April 1, 2006	March 1, 2006	Feb. 27, 2006
July 1, 2006	June 1, 2006	May 30, 2006
Oct. 1, 2006	Sept. 1, 2006	Aug. 30, 2006
Jan. 1, 2007	Dec. 1, 2006	Nov. 29, 2006
April 1, 2007	March 1, 2007	Feb. 27, 2007

Dividends are paid on the first of the month in January, April, July and October. When a dividend payment date falls on a weekend or holiday, the payment is made on the following business day. Only dividend payments that have been approved by the Board of Directors are included in this table.

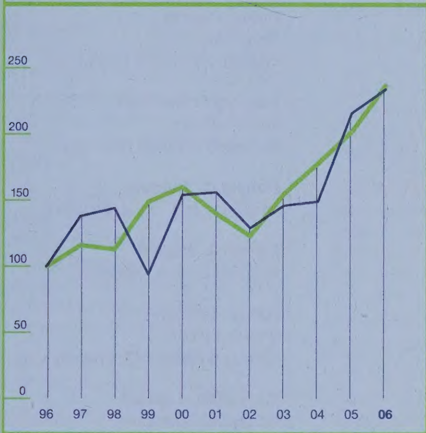
SUBMISSION OF CONCERNS REGARDING ACCOUNTING OR AUDITING MATTERS

In 2002, TransAlta adopted a procedure for employees, shareholders or others to report concerns or complaints regarding accounting or auditing matters on an anonymous, confidential basis to the Audit and Environment Committee of the Board of Directors. Such submissions may be directed to the Audit and Environment Committee c/o the Corporate Secretary of the Corporation.

TOTAL SHAREHOLDER RETURN VS. S&P/TSX COMPOSITE INDEX

(Years ended Dec. 31)

($)



TRANSALTA

100 138 144 94 154 156 129 146 149 216 **234**

S&P/TSX COMPOSITE INDEX

100 116 113 149 160 140 123 155 178 202 **237**

This chart compares what $100 invested in TransAlta and the S&P/TSX Composite Index at the end of 1996 would be worth today, assuming the reinvestment of all dividends.

TEN-YEAR TRADING RANGE & MARKET VALUE VS. BOOK VALUE

($ per share)

MARKET VALUE

22.55 22.60 14.15 22.00 21.60 17.11 18.53 18.05 25.41 **26.64**

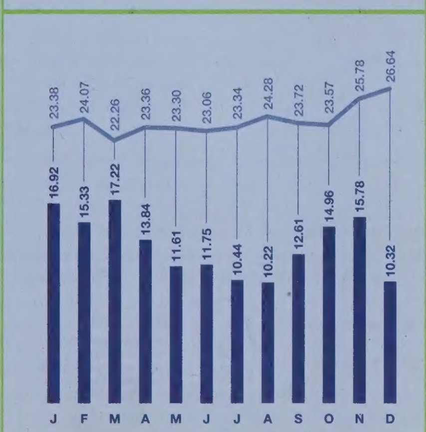
BOOK VALUE

9.96 10.94 10.85 11.61 11.82 12.01 12.90 12.74 12.80 **11.99**

TRADING RANGE

MONTHLY VOLUME & MARKET PRICE

(2006)

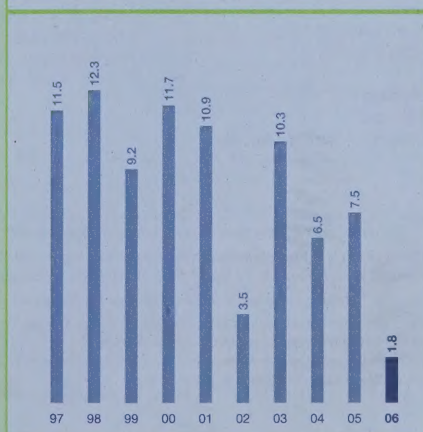


Volume (millions of shares)

TSX closing market price on last day of the month ($ per share)

RETURN ON COMMON SHAREHOLDERS' EQUITY

(%)



CORPORATE INFORMATION

TRANSALTA CORPORATION OFFICERS

Stephen G. Snyder
President &
Chief Executive Officer

Brian Burden
Executive Vice-President &
Chief Financial Officer

Linda K. Chambers
Executive Vice-President,
Generation Technology

Richard P. Langhammer
Executive Vice-President,
Generation Operations

Thomas M. Rainwater
Executive Vice-President,
Corporate Development & Marketing

Ken Stickland
Executive Vice-President,
Legal

Michael Williams
Executive Vice-President,
Human Resources & Communications

Mike Bartel
Vice-President,
Engineering Services

William D.A. Bridge
Vice-President,
Western Canada Operations

Jeff A. Curran
Vice-President & Comptroller

Kelly L. Gunsch
Vice-President,
Commercial Portfolio Management

David Koch
Vice-President,
Financial Operations

Mark B. Mackay
Vice-President,
Energy Technology

Alex R. McFadden
Vice-President,
Major Maintenance

Parviz Mohamed
Vice-President,
Information Technology

Daniel Pigeon
Vice-President,
Portfolio Strategy & Execution

Gregory P. Reinhart
Vice-President,
Generation Human Resources

Donald C. Thomas
Vice-President, TransAlta Wind

Marvin J. Waiand
Vice-President & Treasurer

Jubran Whalan
Vice-President,
Trading & Delivery Optimization

Maryse St.-Laurent
Corporate Secretary

Frank Hawkins
Assistant Treasurer

TRANSALTA SUBSIDIARIES

JoAnne C. Butler
President, TransAlta Mexico,
S.A. de C.V.

Colin J. Mills
Country Manager, TransAlta Mexico
S.A. de C.V.

Doug Jackson
President, TransAlta USA Inc.
Centralia Generation LLC

Troy A. Morrison
Country Manager,
TransAlta Energy (Australia) Pty Ltd.

CORPORATE GOVERNANCE

TransAlta's Corporate Governance Guidelines, Board Charter, Committee charters, position descriptions for the Chair, Committee Chair, President & CEO and codes of business conduct and ethics are available on our website at www.transalta.com. Also available on our website is a summary of the significant ways in which TransAlta's corporate governance practices differ from those required to be followed by U.S. domestic companies under the New York Stock Exchange's listing standards.

ETHICS HELP-LINE

The Audit and Environment Committee of the Board of Directors has established an anonymous and confidential toll-free telephone number for employees, contractors and others to call with respect to accounting irregularities and ethical violations. The Ethics Help-Line number is 1-888-806-6646.

In an effort to be environmentally responsible, please notify your financial institution to avoid duplicate mailings of this annual report.

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AIR EMISSIONS Substances released to the atmosphere through industrial operations. For the fossil-fuel fired power sector, the most common air emissions are sulphur dioxide, oxides of nitrogen, mercury and greenhouse gases.

AVAILABILITY A measure of time, expressed as a percentage of continuous operation 24 hours a day, 365 days a year that a generating unit is capable of generating electricity, regardless of whether or not it is actually generating electricity.

BOILER A device for generating steam for power, processing or heating purposes or for producing hot water for heating purposes or hot water supply. Heat from an external combustion source is transmitted to a fluid contained within the tubes of the boiler shell.

BROWNFIELD ASSET A previously constructed electric power generating facility.

BTU (British Thermal Unit) A measure of energy. The amount of energy required to raise the temperature of one pound of water one degree Fahrenheit, when the water is near 39.2 degrees Fahrenheit.

CAPACITY The rated continuous load-carrying ability, expressed in megawatts, of generation equipment.

CLEAN COAL TECHNOLOGY New technologies such as gasification using solid fuels (coal and coke) to produce power and chemical products with very low emissions.

CO_2 EMISSIONS INTENSITY Amount of carbon dioxide emitted per MWh produced.

COAL GASIFICATION The conversion of solid fuel to gaseous form, for subsequent conversion into power, synthetic gas, hydrogen or a variety of other chemical products.

COGENERATION A generating facility that produces electricity and another form of useful thermal energy (such as heat or steam) used for industrial, commercial, heating or cooling purposes.

COMBINED CYCLE An electric generating technology in which electricity is produced from otherwise lost waste heat exiting from one or more gas (combustion) turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for use by a steam turbine in the production of electricity. This process increases the efficiency of the electric generating unit.

DERATE To lower the rated electrical capability of a power generating facility or unit.

EXPECTED CAPABILITY Plant capacity after consideration of station service use, planned outages, forced and maintenance outages and derates.

FLUE GAS DESULFURIZATION UNIT (SCRUBBER) Equipment used to remove sulfur oxides from the combustion gases of a boiler plant before discharge to the atmosphere. Chemicals, such as lime, are used as the scrubbing media.

FORCE MAJEURE Literally means "greater force". These clauses excuse a party from liability if some unforeseen event beyond the control of that party prevents it from performing its obligations under the contract.

GEOTHERMAL PLANT A plant in which the prime mover is a steam turbine. The turbine is driven either by steam produced from hot water or by natural steam that derives its energy from heat found in rocks or fluids at various depths beneath the surface of the earth. The energy is extracted by drilling and/or pumping.

GIGAJOULE (GJ) A metric unit of energy commonly used in the energy industry. One GJ equals 947,817 BTU.

GIGAWATT (GW) A measure of electric power equal to 1,000 megawatts.

GIGAWATT HOUR (GWh) A measure of electricity consumption equivalent to the use of 1,000 megawatts of power over a period of one hour.

GREENFIELD ASSET A new electric power generating facility built from the ground up on a new site.

GREENHOUSE GAS (GHG) Gases having potential to retain heat in the atmosphere, including water vapour, carbon dioxide, methane, nitrous oxide and hydrofluorocarbons.

HEAT RATE A measure of conversion, expressed as BTU/MWh, of the amount of thermal energy required to generate electrical energy.

MEGAWATT (MW) A measure of electric power equal to 1,000,000 watts.

MEGAWATT HOUR (MWh) A measure of electricity consumption equivalent to the use of 1,000,000 watts of power over a period of one hour.

NET MAXIMUM CAPACITY The maximum capacity or effective rating, modified for ambient limitations, that a generating unit or power plant can sustain over a specific period, less the capacity used to supply the demand of station service or auxiliary needs.

PEAKER PLANT A plant usually housing low-efficiency steam units, gas turbines, diesels or pumped-storage hydroelectric equipment normally used during peak-load periods.

POWER PURCHASE ARRANGEMENT (PPA) A long-term arrangement established by regulation for the sale of electric energy from formerly regulated generating units to PPA buyers.

RENEWABLE POWER Power generated from renewable terrestrial mechanisms including wind, geothermal, solar and biomass with regeneration.

RESERVE MARGIN An indication of a market's capacity to meet unusual demand or deal with unforeseen outages/shutdowns of generating capacity.

RUN RATE The result of extrapolating financial data collected from a period of time less than one year to a full year.

SPARK SPREAD A measure of gross margin per MW (sales price less cost of natural gas).

SUPERCRITICAL TECHNOLOGY The most advanced coal-combustion technology in Canada employing a supercritical boiler, high efficiency multi-stage turbine, flue gas desulfurization unit (scrubber), bag house and low nitrogen oxide burners.

TARGET ZERO TransAlta's initiative designed to drive health, safety and environmental performance to zero lost-time, medical aid and environmental incidents.

TURBINE A machine for generating rotary mechanical power from the energy of a stream of fluid (such as water, steam or hot gas). Turbines convert the kinetic energy of fluids to mechanical energy through the principles of impulse and reaction or a mixture of the two.

TURNAROUND Periodic planned shutdown of a generating unit for major maintenance and repairs. Duration is normally in weeks. The time is measured from unit shutdown to putting the unit back online.

UNPLANNED OUTAGE The shutdown of a generating unit due to an unanticipated breakdown.

UPRATE To increase the rated electrical capability of a power generating facility or unit.

VALUE AT RISK (VAR) A measure to manage earnings exposure from trading activities.

TransAlta™*

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